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

Report Nos.: 50-327/96-02 and 50-328/96-02

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: February 18 through March 30, 1996

Lead Inspector: S. E. Sparks for 4/22/96
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
G. T. MacDonald, Reactor Inspector, Paragraphs 3.2 & 3.6
W. H. Miller, Reactor Inspector, Paragraph 5.1
C. F. Smith, Reactor Inspector, Paragraphs 4.1 - 4.4 & 4.7
P. J. Fillion, Reactor Inspector, Paragraphs 4.1 - 4.4 & 4.7
J. W. York, Reactor Inspector, Paragraphs 4.1 - 4.4 & 4.7
D. E. LaBarge, Senior Project Manager, NRR, Paragraph 4.5

Approved by: 4/22/96
Mark S. Lesser, Chief, Branch 6 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 observations, engineering, plant support, and effectiveness of licensee controls in identifying, resolving, and preventing problems. During the performance of this inspection, the resident inspectors conducted several reviews of the licensee's backshift and weekend activities at the plant.

Enclosure 2

Results:

Plant Operations - Operators were not provided specific guidance regarding pressurizer level, prior to commencing the Unit 1 reactor coolant pump seal replacement outage. This evolution was sensitive and had the potential to result in reactor coolant system leakage into containment (paragraph 2.2.1). Operator safety sensitivity and performance during the Unit 1 forced outage period were good. However, leaking code safety valves continued to provide operational challenges during urit startups from outages (paragraph 2.2.2). A violation was identified for failure to establish or implement procedures for system operation during testing activities. The post maintenance test activity resulted in a perturbation of the component cooling system and subsequent damage to other equipment (paragraph 2.2.3).

Maintenance - A Unit 1 reactor coolant pump seal replacement activity was not accomplished correctly the first time and required rework to allow unit restart (paragraph 3.1). The emergent work due to the 1A1 diesel governor servo booster extended the outage from a planned approximate 36-hour duration to approximately 50 hours (paragraph 3.2). Outstanding work requests noted during a Unit 1 control panel walkdown after the outage indicated additional attention was needed to focus resources on equipment deficiencies (paragraph 3.3). Common station service transformer maintenance by customer group caused voltage spikes which unnecessarily challenged operators (paragraph 3.4). Observed surveillances were performed in a good manner (paragraph 3.5). Review of maintenance related Problem Evaluation Reports indicated that licensee activities for resolution of problems with diesel generator 1B-B electronic governor settings, main feedwater steam supply check valves, main transformer sudden pressure relays, circuit breaker spare parts, and the OT2 handswitch failure evaluation were adequate (paragraph 3.6.2).

Engineering - Design features associated with component cooling surge tanks contributed to worsening of the system event discussed in the Operations area (paragraph 2.2.3). Design change notices reviewed were determined to be technically adequate and had been prepared in accordance with requirements. Balance of plant equipment problems, which impacted the units' operations were corrected by plant modifications which resolved the root causes of the problems. Concerns related to TVA's Engineering Safety Assessment failure to identify new failure modes of the rod control system; and to correctly identify surveillance tests to be performed at the beginning of each fuel cycle as compensatory measures, were identified as an unresolved item (paragraph 4.1). Operability evaluations were determined to be performed in a technically adequate manner (paragraph 4.2). Problem Evaluation Reports generally demonstrated adequate resolution with appropriate identification of root causes, extent of condition evaluations, and developed corrective actions for recurrence control (paragraph 4.3). A violation for failure to control implementation of plant modifications in accordance with procedures was identified (paragraph 4.6).

Plant Support - In the Fire Protection Area, a violation involving the failure to provide appropriate storage for the pumps and accessories to be installed as part of the upgrade to the fire protection water supply system was identified. Implementation of fire prevention procedures was satisfactory,

except transient combustible permits were being used for the permanent storage of materials which did not meet the intent of the procedure. Also, the list of automatic sprinkler valves in one procedure had several valve numbers that were different from the identification tags on the installed valves. Surveillance testing of fire protection equipment was performed within the required time schedule. However, the required replacement of belts for the diesel generator building CO_2 system was not accomplished in a timely manner in 1994. Fire brigade organization, staffing, training, equipment, and drill performance were satisfactory. Fire protection audits were thorough and identified a number of discrepancies. However, corrective actions and resolution of the identified problems were frequently not accomplished in a timely manner (paragraph 5.1). In the Radiological Protection Area, good ALARA sensitivity by both health physics technicians and other plant personnel was observed during Unit 1 outage (paragraph 5.2).

REPORT DETAILS

Acronyms used in this report are defined in paragraph 11.

1.0 PERSONS CONTACTED

Licensee Employees

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

Nuclear Regulatory Commission Employees

*Holland, W., Senior Resident Inspector
*Starkey, R., Resident Inspector

* Attended exit interview.

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

On March 18, 1996, the licensee implemented changes to the Sequoyah site organization, including several management changes. Organization changes included having the Training Department Manager report directly to the Site Vice President and creating an Engineering and Support Services Manager position reporting to the Site Vice President. Reporting to the new manager are the managers of Engineering and Materials, Site Support, Business and Work Performance, Projects, and Programs. The Technical Support Manager reports to the Engineering and Materials Manager. Also, the Scheduling Group reports to the Assistant

Plant Manager. Management changes included Mr. Jon Rupert being selected as the Engineering and Support Services Manager and Mr. Mark Skarzinski being named the Technical Support Manager.

On March 21, 1996, the Sequoyah Site Vice President announced organizational changes as a result of the resignation of the Plant Manager, effective March 29, 1996. Interim changes, effective March 22, included the Assistant Plant Manager, the Maintenance and Modifications Manager, and the Acting Operations Manager reporting directly to the Site Vice President. In addition, Mr. Bill Lagergren was appointed to be Acting Operations Manager.

2.0 **PLANT OPERATIONS** (71707)

2.1 PLANT STATUS

Unit 1 began the inspection period in power operation. The unit operated at power until March 1, 1996, when the unit was shut down and cooled down to replace a reactor coolant pump motor and RCP seal package. The RCP maintenance activity is further discussed in paragraphs 2.2.1 and 3.1. After maintenance activities were completed, Unit 1 was restarted (MODE 2) on March 13 and reconnected to the grid on March 14, 1996. The unit operated at power for the remainder 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:

2.2.1 UNIT 1 RCP SEAL REPLACEMENT SENSITIVE ACTIVITY PREPARATION/CONTROL

On March 1, 1996, Unit 1 entered a forced outage to replace the #2 RCP motor and pump cartridge seal package (see paragraph 3.1). During the evolution, the RCS was not considered to be breached since the pump impeller/shaft assembly (approximately 6000 pounds) would be on its back seat. On February 28, 1996, engineering completed TSIR 96-NSS-68-299, which stated that an upward pressure of approximately 15 psig would be required to lift the pump assembly off its back seat and thus allow reactor coolant inventory to exit the RCS. The evaluation further stated that based on the predicted PZR level targeted for the evolution (30%), the impeller would already experience a lifting force of approximately 11 psig due to system static pressure, leaving very little pressure control margin (approximately 4 pounds) for the operator to prevent loss of RCS inventory. The TSIR established five conditions to be maintained for minimizing the probability of losing RHR and to prevent inventory loss from the RCS. One of those five conditions

required "monitoring of RCS inventory to ensure level is maintained in the pressurizer." However, no maximum PZR level (to ensure that the RCP remained backseated) or operating range was provided as guidance to operators.

On March 3, 1996, two days into the forced outage, operators raised a question as to what PZR level operating band should be maintained while the RCP was on its back seat. To address that question, a second TSIR, TSIR 96-NSS-068-306 was written on March 3. This TSIR provided an operating range of 20-30% PZR level with a maximum PZR level of 32.1% PZR cold calibration. Additionally, on March 3, 1996, several changes were made to AOP-R.05, RCS LEAK AND LEAK SOURCE IDENTIFICATION, Revision 0, to support the RCP outage.

On March 4, 1996, the inspectors became aware of the TSIR and AOP revisions which had taken place during the weekend of March 2-3. They expressed concern to plant management regarding the appearance of last minute guidance to operators and changes to an AOP. The inspectors believed that these changes, two days into the forced outage, indicated a lack of adequate preparation for the sensitive activity associated with the seal package replacement. Later on March 4, the licensee issued Standing Order 96-029, Monitoring of RCS Parameters During U-1 RCP Seal Replacement. The Standing Order directed operators to monitor RCS parameters continuously and assigned a dedicated licensed operator to this function.

After reviewing the sequence of events that occurred on March 3, the inspectors concluded that the questioning attitude of the on-shift operators during evolution briefings resulted in better preparation for this sensitive activity. However, the inspectors also concluded that operators were not provided certain essential guidance, prior to commencing the outage, for an evolution that was sensitive and which had the potential to result in RCS leakage into containment. Specifically, operators were not given a maximum PZR level or a PZR level operating range which would preclude lifting the RCP pump assembly. Additionally, operations review of procedures prior to the outage was not thorough.

On March 7, 1996, the site quality assurance organization wrote PER No. SQ960574PER, which confirmed the inspectors' concerns and also identified several planning, scheduling, and communications errors associated with the RCP forced outage.

2.2.2 REVIEW OF UNIT 1 OPERATIONS DURING THE FORCED OUTAGE PERIOD

During the Unit 1 forced outage period, March 1 through March 12, 1996, the inspectors reviewed Unit 1 activities specifically associated with plant shutdown, shutdown operations, and plant restart. The inspectors focused on operator monitoring of important parameters during reactor coolant pump seal replacement and noted that operators were assigned to continually monitor parameters associated with RHR, pressurizer level, and RCS inventory (RVLIS). In addition, other barriers established included switchyard protection and limiting of DG activities to assure

decay heat removal was not interrupted. The inspectors noted additional operators, both ROs and SROs, were made available and used to support specific outage activities. In addition, unit shutdown and restart was accomplished in a good manner. However, during restart, problems with the RCP #2 seal and a simmering RCS code safety valve caused additional unit maneuvering. The RCP #2 seal problem is further discussed in paragraph 3.1.

On March 13, 1996, with Unit 1 at normal operating pressure (2235 psig), one of the three RCS code safety valves indicated slight leakage. Operators immediately reduced pressure in accordance with procedures to approximately 2080 psig, where the leaking code safety valve reseated. During the next 20 hours, the licensee repressurized the RCS to normal operating pressure at a rate of 10-15 psi per hour. RCS safety valve leakage was not observed during this pressurization evolution.

The inspector monitored licensee activities relating to RCS code safety valve leakage during this period. It was noted that similar code safety valve leakage had been observed during past outages. PERs had been written to address this issue; however, corrective actions had not been effective in eliminating this operational problem.

The inspector concluded operator performance during the outage period was good. In addition, operator response to the leaking code safety valve was good. However, leaking code safety valves continued to provide operational challenges during unit startups from outages.

2.2.3 UNIT 1 CCS SURGE TANK OVERFLOW EVENT

On March 20, 1996, the MCR received numerous alarms related to CCS Surge Tank level and CCS "B" train flow. During this time period, the CCS "A" surge tank overflowed through the tank vent valve, 1-FCV-70-66, a normally open, air-operated valve, located on the top of the tank. The tank overflow was discharged through the vent valve to the surrounding area of the 734' elevation of the auxiliary building (the vent valve does not have a tail pipe to direct water to the floor or to a sump, but is open directly to the atmosphere at the top of the tank) and sprayed the two nearby RCW booster pumps, one of which was running. RCW booster pump "B" tripped as a result of the spray down. Later it was determined that damage had been done to the pump motor, which had to be replaced. Additionally, the "A" train Auxiliary Control Air System moisture alarm, believed to have been initiated by the overflow event, annunciated in the MCR (the auxiliary air compressor skids are located near the CCS surge tanks).

When RCW booster pump flow was lost, all the glycol chillers on both units tripped. The RCW booster pumps supply cooling water to the glycol chillers which maintain the containment ice condenser at its TS required temperature of less than or equal to 27 °F. Operators were reluctant to start RCW booster pump "A", which had been in standby, since it had also been sprayed by the overflowing CCS surge tank. After approximately 30 minutes, operators restored flow to the glycol chillers by starting two

additional main RCW pumps which are located in the turbine building. The two additional RCW pumps (a total of four were now in service) provided sufficient flow to allow restart of the glycol chillers. During the time the glycol chillers were tripped, the ice condenser floor temperature high alarm was received in the MCR; however, at no time did the temperature exceed the TS limit.

This event occurred during performance of a PMT on CCS valve 1-FCV-70-75, a CCS return isolation valve, following an Arrowhart breaker changeout. During performance of the PMT, 1-FCV-70-75, a normally open and deenergized valve, was stroked closed. With the valve closed, a water inventory imbalance developed in the in-service CCS "B" train which resulted in a level decrease in the "B" CCS surge tank and a level increase in the "A" CCS surge tank. Surge tank level makeup was automatically initiated on both tanks. Makeup to the "B" surge tank occurred due to an actual tank low level. Makeup to the "A" tank occurred due to the design of the tank level instrumentation which uses a "dry" reference leg. When the normally "dry" reference leg became filled due to the high level in the tank, the level transmitter failed low and makeup to the tank automatically initiated, thus worsening the condition of the already overfilled tank. When operators realized that the tank was overflowing, they manually closed the makeup valve.

The inspectors reviewed PER No. SQ960759PER, which described the event, read the personnel statements of the operators involved with the evolution, and were briefed by operations supervision. The inspectors questioned whether the CCS was aligned by an approved procedure prior to closing 1-FCV-70-75. The PMT prerequisites stated that operations was to ensure that system alignments and configuration were suitable for performance of the PMT. The inspectors concluded that there was not a procedure for operating 1-FCV-70-75 while CCS "B" train was in service. The inspectors determined that procedure 0-SO-70-1, COMPONENT COOLING WATER SYSTEM "B" TRAIN, Revision 8, could have been used to shutdown the CCS "B" train, thus preventing the event from occurring. The inspectors also concluded that procedure 0-SO-70-1 was not used because operators, planners, and reviewers did not fully understand the effect, on the CCS "B" train, of isolating a portion of the train while the train was in operation. The inspectors further concluded that a contributing factor in the licensee's decision for not stopping CCS "B" train was the reluctance to enter the Action Statement of TS 3.7.3, Component Cooling Water System (for both units), which would have been required if the "B" train had been shutdown. Subsequent to this event, the CCS "B" train was shutdown, the Action Statement entered, and the PMT on 1-FCV-70-75 was successfully completed.

On March 28, 1996, the Operations Superintendent issued Standing Order 96-036, which required, in part, that all equipment manipulations required to align a component for testing must be in accordance with approved plant instructions. The Standing Order further stated that any deviation from a reviewed action plan requires that the evolution be suspended until an SRO and the SOS review the entire evolution to ensure that the change is appropriate and procedurally controlled.

The inspectors concluded that the licensee failed to provide an approved procedure for operating 1-FCV-70-75, or to shutdown CCS "B" train in accordance with an existing procedure, 0-SO-70-1. Either of those actions, if implemented, should have prevented the perturbations which occurred in the CCS system. The failure to establish or implement a procedure is considered a violation on TS 6.8.1 and is identified as VIO 327, 328/96-02-01, Failure to Establish or Implement Procedures for Component Cooling System Operation During Testing Activities.

The inspectors noted that there are two design features of the CCS surge tanks which contributed to the worsening of this event. First, it would appear that each time there is an abnormally high level in a CCS surge tank, the level instrument "dry" reference leg will fill, resulting in failed low level indications in the MCR, and initiating level makeup, thus worsening the overflow condition. Second, when the "A" tank overflows through the vent valve there is the potential that damage can occur to the RCW booster pumps or other equipment located in the area since the flow from the vent valve is not directed to a floor drain or away from other sensitive equipment. The inspectors will review the licensee's corrective actions related to PER No. SQ960759PER. This inspector followup item is identified as IFI 327, 328/96-02-02, Review Corrective Actions of PER No. SQ960759PER Regarding CCS Surge Tank Overflow.

As a part of this inspection activity, the inspector reviewed UFSAR Section 9.2.1, COMPONENT COOLING SYSTEM. No discrepancies were noted between that part of the CCS inspected and Section 9.2.1.

2.3 BIWEEKLY INSPECTIONS

The inspectors conducted biweekly inspections, using the licensee's IPE information, to verify operability of the following Engineered Safety Features trains.

The licensee's IPE states that the shutdown boards are one of the most important plant systems contributing to core damage frequency. On February 27, 1996, the inspector performed a visual inspection of the 6900 volt shutdown boards 1A-A and 2A-A. The inspector was specifically looking for any indication of outstanding WRs or any other visible deficiencies, such as tripped relays. The inspector used the appropriate wiring diagrams while performing the inspection. With the exception of two burned out light bulbs on the breaker indicating lights, no deficiencies were observed and each breaker was determined to be in its correct open or closed position. The inspector concluded that the 6900 volt shutdown boards 1A-A and 2A-A were properly aligned.

The inspector reviewed UFSAR Section 8.3, ONSITE POWER SYSTEM, and did not note any discrepancies between the plant and the UFSAR description of the 6900 volt shutdown boards.

2.4 MONTHLY INSPECTIONS

On March 5 and March 6, 1996, the inspector selected two safety-related tagouts and ensured that the tagouts were properly prepared and implemented by verifying correct placement of tags on breakers, switches, and accessible valves. The inspector also observed that the tagged components were in the required positions. The tagouts reviewed were 1-HO-96-0320, RCP #2 ERCW and CCS U1, and 1-HO-96-0321, Unit 1 RCP Motor #2. These hold orders were implemented to allow replacement of the Unit 1 RCP motor and seal package. The inspector concluded the two tagouts were correctly prepared and implemented.

Within the areas inspected, one violation and one IFI was 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 UNIT 1 REACTOR COOLANT PUMP SEAL REPLACEMENT ACTIVITY

During the week of March 3-9, 1996, the inspectors reviewed the licensee's maintenance activities associated with removal of a leaking seal assembly and installation of a new cartridge seal package for the Unit 1, RCP #2 (WO 95-14830-00). The activity was worked on a 24-hours-a-day/3-shift basis. The inspector's review included observation of on-going work activities, review of the hold orders associated with the maintenance (paragraph 2.4), and review of the completed work package for WO 95-14830-00.

Activities observed by the inspectors indicated the maintenance was being performed in a good manner; however, on March 8, 1996, during pressurization of the Unit 1 Reactor Coolant System, a 1-2 gpm leak was observed from the #2 RCP seal. Plant conditions were established to rework the seal package. During the seal disassembly, the licensee determined that an O-ring had not been installed during the initial maintenance activity. PER No. SQ960647PER was written addressing this discrepancy. The PER was classified as level A, which is the highest significance level a PER can receive. The O-ring was properly installed and the seal package was reassembled. Subsequent PMT at normal operating pressure (2235 psig) did not identify any leakage from the seal.

The inspectors reviewed the completed work package for WO 95-14830-00 and noted the following:

- The old seal removal evolutions were performed in a manner which identified the probable cause of the old seal leakage. This was

determined to be an O-ring in the upper portion of the cartridge being forced out of position during pump operation. PER No. SQ960812PER was written to address this issue. The licensee intends to conduct additional evaluation of this problem as part of the PER corrective action.

- The procedure used for pump seal replacement was MI-10.2.3, REMOVAL, INSPECTION AND REPLACEMENT OF REACTOR COOLANT PUMP CARTRIDGE AND NUMBER 1 SEALS, Revision 5. The evolutions involved in the maintenance activity required a combination of craft skills and engineering support to allow for adequate performance of the activity as written in the MI.

- Documentation for completion of some steps was unclear, requiring clarification from the licensee. Examples were step 6.22[4] which required installation of a set screw. The licensee stated the required action was performed in a previous step. Also, steps 6.22[30] and 6.22[31] requiring coating of capscrews with a sealant was marked as not applicable. The licensee stated these steps were not applicable because they addressed a condition for additional sealant which was not required.

- Procedure documentation supported adequate job performance with the exception of steps 6.21[6] and 6.21[7]. These steps were not performed and resulted in leaving an O-ring out of the pump seal package, and subsequent seal leakage during RCS pressurization. This issue was discussed above.

- Craft documentation of actual work performed discussed some problems encountered including pitting on the pump shaft, misplaced bolts, and torquing problems. The inspectors noted that the work package did not identify if PERs were written for these issues. The inspectors subsequently determined that PERs were written for the pitting observations on the pump shaft, and for the misplaced bolts. However, the torquing problem was not identified in a PER.

The inspectors concluded that the maintenance activities for the Unit 1, RCP #2 seal replacement were not accomplished as required, resulting in leakage past the seal during Unit 1 pressurization. The inspectors will followup on the licensee's PER disposition during a future inspection. This item is identified as IFI 327/96-02-03, Followup On Licensee Evaluation, Cause Determination, and Corrective Actions for PER No. SQ960647PER Associated With Incorrect Assembly of the Unit 1, #2 RCP seal During Maintenance.

The inspectors reviewed UFSAR Section 5.5.1.2, REACTOR COOLANT PUMPS, DESIGN DESCRIPTION, and UFSAR Section 5.5.1.3.1, REACTOR COOLANT PUMPS, PUMP PERFORMANCE, and did not note any discrepancies between the plant and the UFSAR description of the RCP seal cartridge.

3.2 DIESEL GENERATOR MAINTENANCE AND TROUBLESHOOTING

The inspector observed maintenance activities associated with a planned LCO outage on DG 1A-A. 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 half of the available LCO action time of 72 hours. The LCO action was entered at 11:25 p.m. on February 27, 1996.

The inspectors reviewed UFSAR Sections 8.3, 9.5.4, 9.5.5, 9.5.6, 9.5.7, and Work Orders 951248000, 951243700, 950289600, 950314900, 950330800, 950329000, and 951296900. Mechanical maintenance on flex hoses, auxiliary lube oil circulating pump couplings and DG cooling water heat exchanger inspections was good. The 1A2 DG governor servo booster was replaced due to previous sluggish operation. A discrepancy was noted with the documentation of this activity when a 575 Parts Issue Form was lost for one of the new fittings. A new fitting was installed and the documentation for the new fitting was added to the work package.

The pressure switch replacement activities were good; however, a documentation discrepancy was noted in WO 951296900 which called for QA level III replacement pressure switches. Two of the six pressure switches in the WO were for class 1E lube oil pressure applications which required safety related parts. QA level III was a nonsafety related part designation. The instrument data sheet for the lube oil applications called for a class 1E switch and the actual replacement switches installed were QA level I nuclear grade switches. The inspectors verified that nuclear grade QA level I pressure switches were installed in the class 1E applications. The licensee indicated that the WO called for QA level III switches because the switches had previously been listed in the stock code database as a level III part. The inspector witnessed calibrations of four pressure switches which were satisfactory.

At 1:40 a.m. on February 29, 1996, DG 1A-A was to be started for PMT on the 1A1 DG air start system using a local idle start. The DG rolled but did not start and a "failed to start" alarm was received. At 3:30 a.m. a troubleshooting package WRC195410 was prepared. A second start was initiated at 5:35 a.m. after the DG was instrumented. The DG started on the second attempt but was slow to start and the governor response was sluggish. The troubleshooting efforts were good and determined that the 1A1 governor servo booster had failed.

At approximately 3:00 p.m. the corrective maintenance to replace the servo booster was initiated. Corrective maintenance appeared fragmented and had problems. The initial replacement servo booster flange bolt holes would not align with the support bracket. A second servo booster was obtained and installed. Existing air fittings would not fit the new servo booster and new fittings were obtained. There were difficulties in installing the new fittings due to an interference problem with the booster adjustment setscrew. DG 1A-A was declared operable at 1:19 a.m., on March 1, 1996.

The inspector reviewed the DG vendor manual and could find no recommended maintenance or replacement interval for the servo boosters. The licensee indicated that the vendor had not specified a replacement interval for the booster. DG 2A1 had its servo booster replaced approximately two years ago. The two servo booster replacements for DG 1A-A brought the total to three of the eight servos which had failed and required replacement. DGs 1B-B, 2A-A, and 2B-B have been individually tested to start their respective DG within the last seven weeks. The licensee had refurbished the DG governors but had not replaced the servo boosters. The inspector noted that the 575 Parts Issue Form for the new servo booster indicated that the booster had a shelf life specified, indicating that some parts of the booster could degrade over time when stored. Not having a replacement interval or scheduled preventive maintenance for the booster when a shelf life was specified for the item appeared to be inconsistent and seemed to indicate a discrepancy in the PM program for the DG.

The inspector concluded the DG 1A-A outage was not well executed. The emergent work due to the 1A1 DG governor servo booster, extended the LCO outage from a planned approximate 36-hour duration to approximately 50 hours. The maintenance on scheduled work in the LCO outage was better than the emergent corrective maintenance which appeared fragmented.

3.3 UNIT 1 CONTROL PANEL WALKDOWNS

During the Unit 1 forced outage (March 1 through March 14), the inspector conducted several control panel walkdowns reviewing maintenance requests that were attached to different component indicators or operators. The inspector discussed specific observations with operators and SROs during the walkdowns.

On March 21, 1996, the inspector conducted a Unit 1 MCR panel walkdown with the Unit Manager. The inspector noted that 20 work requests were outstanding for work associated with annunciator windows. In addition, over 40 work requests were noted to be outstanding for work associated with control panel instrumentation and/or other equipment. Some of the work requests were identified as being in testing status, while others were scheduled to be worked online. Several of the work requests had been written during unit restart.

The inspector concluded that required work had been accomplished to support Unit 1 restart after the forced outage in March 1996. However, the outstanding amount of work identified during the control panel walkdowns indicated additional attention was needed to focus resources on equipment deficiencies which could distract operators attention to performance of their duties.

3.4 Maintenance on CSST Causes Overvoltage Condition

On February 29, 1996, at approximately 2:10 p.m., an overvoltage alarm annunciated in the MCR, and Unit 1 operators observed the 1 B-B shutdown

board voltage read offscale high three times. The total time the voltage was offscale high was less than 30 seconds.

The inspector spoke with the unit operator who had observed the instrument spiking, attended a post turnover meeting held to discuss the voltage spike and potential corrective actions, and reviewed PER No. SQ960472PER written to document this event.

Based on this review, the inspector determined that a personnel error during a PMT on the 'X' autotap changer for CSST A caused the spikes. The PMT used a voltage veriac to simulate voltage changes to the CSST. During the PMT, a Customer Group technician set the control relay input voltage too low, causing the autotap changer to raise the 1B-B shutdown board voltage above 7400 volts. Further attempted corrections by the technician caused the repeated voltage spikes. The inspector determined that the procedure for the PMT was being clarified to match plant conditions (the veriac would not be used on an operating CSST).

The inspector also reviewed the engineering evaluation for the overvoltage condition. The evaluation determined the voltage spike reached 107% of rated voltage. Plant equipment is designed to handle 110 to 125% of rated voltage. A previous overvoltage event in 1993 was more extreme with no damage incurred. Based on this information, the evaluation concluded that no significant equipment degradation was experienced as a result of this event, and that the loads fed from the shutdown board were operable for the entire event.

The inspector concluded that the Customer Group performed activities which unnecessarily challenged the unit operators. The inspector also concluded that operations reacted appropriately and displayed the correct sensitivity to the event.

The inspector reviewed UFSAR Section 8.2.1.8, OFFSITE POWER SYSTEM, FUNCTIONAL MEASURES, and did not note any discrepancies between the plant and the UFSAR description of the CSSTs.

3.5 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 technical specifications and other requirements. The inspection included a review of the following procedures and observation of surveillance:

3.5.1 REVIEW OF CONTAINMENT SPRAY PUMP 1B-B TESTING

On March 5, 1996, the inspector observed performance of 1-SI-SXP-072-201.B, CONTAINMENT SPRAY PUMP 1B-B PERFORMANCE TEST, Revision 0, and reviewed the SI test data upon completion of the test. The SI assessed the operational readiness of CS Pump 1B-B and check valves 1-72-507 and 1-72-529 and was performed in accordance with ASME/ANSI Section XI

requirements. The inspector discussed the SI with the AUO who was performing the test and with the system engineer who was monitoring system performance. The inspector concluded that the SI met its acceptance criteria and that the surveillance was conducted in a good manner.

As a part of this inspection activity, the inspector reviewed UFSAR Section 6.2.2, CONTAINMENT HEAT REMOVAL SYSTEMS. No discrepancies were noted between the plant and that part of the Section 6.2.2 which discussed the containment spray system.

3.5.2 REVIEW OF RHR PUMP 1B-B TESTING

On March 22, 1996, the inspector observed performance of 1-SI-SXP-074-201.B, RESIDUAL HEAT REMOVAL PUMP 1B-B PERFORMANCE TEST, Revision 0. The purpose of the SI was to demonstrate operational readiness of the RHR pump. The inspector also reviewed a copy of the test data after completion of the test. The inspector noted, during walkdown of the 1B-B RHR pump room that lights were burned out in the room, requiring the use of a flashlight to observe some pump parameters. The inspector discussed the SI and the room lighting observation with the system engineer who was monitoring system performance. The inspector concluded that the SI met its acceptance criteria and that the surveillance was conducted in a good manner.

As a part of this inspection activity, the inspector reviewed related portions of the UFSAR Section 6.3, EMERGENCY CORE COOLING SYSTEM, and Section 6.8, PUMP AND VALVE INSERVICE TEST PROGRAM. UFSAR Section 6.8 described the licensee's pump and valve inservice testing program for the first 10-year inservice inspection period. However, the licensee commenced the second 10-year inservice inspection period in December 1995. The licensee intends to remove Section 6.8 from the UFSAR as discussed in NUREG-1482, GUIDELINES FOR INSERVICE TESTING AT NUCLEAR POWER PLANTS. The UFSAR revision will be accomplished as part of DCN S-12020-A which was initiated on December 12, 1995. No other discrepancies were noted.

3.5.3 REVIEW OF UNIT 1 SSPS TRAIN A TESTING

On March 28, 1996, the inspector observed performance of SI-90.8, REACTOR TRIP INSTRUMENTATION MONTHLY FUNCTIONAL TEST (SSPS), Revision 14. The SI delineated the procedures for functionally testing and calibrating the SSPS from the input relays through the undervoltage output coils, master relays, and the multiplexors.

The inspector reviewed the SI procedure, attended the pretest briefing, and observed portions of the test in the MCR, the auxiliary instrument room, and in the rod drive control room. The inspector noted, during the prejob briefing, that management emphasized stopping the test if any questions or problems arose, that management oversight was present at the three locations during the test, that the procedure was followed step-by-step through the test. Communications during the test appeared

clear and effective. The inspector concluded that the SI met its acceptance criteria and that the surveillance was conducted in a very good manner.

As a part of this inspection activity, the inspector reviewed UFSAR Sections 7.2.2.2.3, 6.a and b, REACTOR TRIP SYSTEM, CHECK OF INPUT RELAYS, and CHECK OF LOGIC MATRIXES. No discrepancies were noted between the plant and the UFSAR.

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 FOLLOWUP ON OT2 HANDSWITCH FAILURE

NRC IR 327, 328/96-01 described maintenance performed by the FIN team under WR C325891 on Westinghouse OT2 Handswitch 1-HS-63-157A on January 22, 1996. The switch did not actuate its respective motor operated valve 1-FCV-63-157 during a surveillance test. High switch contact resistance was measured. The resistance dropped after the switch was cycled. Subsequent resistance checks were satisfactory and the surveillance test was completed. PER No. SQ960112PER was generated for this incident. Maintenance history review identified PER No. SQ951531PER which was generated for another failure of a Westinghouse OT2 switch. IFI 327, 328/96-01-01 was identified for followup on the OT2 handswitch failures.

During this period, the inspector reviewed PER Nos. SQ960112PER, and SQ951531PER, and licensee procedure SSP 6.4, EQUIPMENT HISTORY AND FAILURE TRENDING, Revision 3, to determine if there was a generic aging degradation concern with the OT2 handswitches. The licensee properly evaluated the switch failures. The failure mechanisms for the two OT2 switch failures were different and did not represent a generic aging degradation concern. The evaluation of this issue was satisfactory and IFI 327, 328/96-01-01, Followup on OT2 Handswitch Failures was closed.

3.6.2 FOLLOWUP ON DG 2B-B TROUBLESHOOTING

NRC IR 327, 328/96-01 discussed a maintenance outage on DG 2B-B under LCO conditions. DG 2B-B governor control system problems were noted on January 25, 1996, during PMT engine runs. DG 2B-B did not properly respond to load controls when paralleled to the grid and was stopped using the emergency stop pushbutton. The rate of DG loading and non optimized electronic governor gain and reset settings contributed to the load control problems. The licensee adjusted the electronic governor gain and reset settings per the vendor recommendations and subsequent DG load testing showed improved governor engine control. A PMT to verify proper DG response in accident mode could not be prepared and conducted within the remaining LCO time and the electronic governor gain and reset

settings were returned to the original values. Guidance regarding DG loading was provided to the operators.

The inspectors reviewed UFSAR Sections 8.1 and 8.3, PER No. SQ960143PER, and Woodward 2301A Electronic Load Sharing and Speed Control 9905 Series Installation, Operation and Calibration Manual 82389H (contained within Sequoyah vendor manual SQN-VTM-P318-0010). Troubleshooting WO 960065900 on DG 2B-B and the original DG electronic governor modification installation work orders 9501297-03, 9501834-03, 9404237-03, and 9404237-04. WO 960065900 documented the original DG electronic governor gain and reset settings prior to the adjustments. This allowed the licensee to return the gain and reset settings for the 2B-B DG to the original values. The inspectors reviewed the electronic governor modification installation WOs and verified that the initial settings and the gain and reset adjustment procedure followed the recommended process in the vendor manual. The inspectors concluded that licensee activities regarding DG 2B-B troubleshooting were adequate.

3.6.3 FOLLOWUP ON MAIN FEEDWATER STEAM SUPPLY CHECK VALVE FAILURE

NRC IRs 327, 328/95-15 and 96-01 described the licensee's evaluation of a failure of the 1B main feedpump low pressure steam supply check valve, 1-VLV-1-606, documented in PER No. SQ950619PER. The licensee's check valve program grouped valves, and 1-VLV-1-606 was one of 14 ten-inch Walworth swing check valves in a check valve group. 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. The licensee evaluation was adequate.

The inspectors reviewed UFSAR Section 10.3, 10.4.7.1, and 10.4.7.2, corrective actions for PER No. SQ950619PER, and SSP 8.53, CHECK VALVE PROGRAM, Revision 1. Corrective action step 10 of the PER required the licensee to initiate periodic system walkdowns per SSP 8.53 Section 3.0 step 7 for the remaining valves in the group. The Unit 1 main feedwater steam supply check valves were in constant service and were disassembled and inspected. Audible banging noises were noted on failed valve 1-VLV-1-606 for at least four weeks prior to the failure. The inspectors observed the four main feedwater steam supply check valves and did not hear any audible evidence of check valve tapping.

On July 21, 1995, the licensee performed the walkdown of the 14 valves in the ten-inch Walworth check valve group. All valves were checked for unusual noise, tapping, and visual vibration. The walkdown was performed to SSP 8.53 Appendix A requirements. The inspectors reviewed the data sheets and noted that the AFW and Auxiliary Boiler check valves 1-VLV-3-810, 2-VLV-3-810, 1-VLV-12-503, and 2-VLV-12-502 were inspected under no flow standby conditions. There were no supplemental walkdown checks scheduled during conditions when the standby systems would be in operation, only the routine system engineer inspections would be performed to detect check valve degradation. Closeout of the corrective action step for periodic walkdowns for the affected group when four

standby check valves were observed under no flow conditions was considered an example of weak corrective action verification.

3.6.4 FOLLOWUP ON MAIN TRANSFORMER SUDDEN PRESSURE RELAYS

NRC IRs 327, 328/95-16, and 96-01, and LER 327/95-10 discussed a failure of a main transformer sudden pressure relay which caused an inadvertent actuation of A phase Unit 1 main bank transformer. The licensee formed a team to evaluate relay performance and failures within the TVA system. The team concluded that the actuation was caused by relay bellows deformation due to overpressurization with the relay isolated during transformer maintenance activities.

The inspectors reviewed UFSAR Sections 8.1 and 8.2, PER No. SQ950768PER, the Customer Group Field Test Manual Section K17-1, and the Sudden Pressure Relay QIT Evaluation Presentation dated February 15, 1996. The QIT evaluation included data and sudden pressure relay events TVA wide including events at Browns Ferry Nuclear Plant and Shawnee Steam Plant. One sudden pressure relay event at Browns Ferry also involved an operation with the relay valve closed but the bellows did not deform. The TVA Customer Group Field Test Manual provided guidance to leave the relay isolation valve open during relay testing.

The QIT team evaluation was thorough and included testing and relay performance and experience at other nuclear utilities. The relay isolation valve must remain open to prevent relay deformation. The corrective action recommendations included procedure, training and design issues. The corrective actions were not yet implemented. The management decision to pursue a design solution utilizing a pressure relief device on the relays demonstrated a conservative decision to achieve a permanent solution.

3.6.5 FOLLOWUP ON CIRCUIT BREAKER SPARE PARTS

NRC IR 327, 328/95-25 identified a problem with the control of spare parts for Westinghouse type DS circuit breakers. Warehouse database descriptions did not contain correct data to control end use for DS 206, DS 416, and DS 532 circuit breaker operating mechanism spare parts. Operating mechanism spare parts for DS 206 and DS 416 circuit breakers were incorrectly identified as suitable for DS 532 circuit breaker applications.

The inspectors reviewed UFSAR Section 8.3 and PER No. SQ952213PER. The corrective actions included correction of parts descriptions in the warehouse database, initiation or purchase requests for correct spare parts, and an evaluation of other items on the contract which procured the operating mechanism (81N-308613). These corrective actions were adequate and complete.

The root cause appeared to be unclear written communication due to an assumption in the purchase request that the parts were interchangeable, and inattention to detail. The contract evaluation was reviewed and was

determined to be thorough. Three other spare parts items on contract 81N-308613 were determined to be potential examples of the same discrepancy. The licensee's actions to review warehouse database descriptions and to surplus parts were adequate. None of the material was issued to the plant for inappropriate applications. The corrective actions for this issue were satisfactory.

3.6.6 (CLOSED) LER 327/95-10, Turbine and Reactor Trips Resulting From a Failure of the 'A' Phase Main Transformer Sudden Pressure Relay. This issue involved the spurious actuation, on July 17, 1995, of a sudden pressure relay located on the "A" phase main transformer, causing the turbine trip and subsequent Unit 1 reactor trip. This event was discussed in IR 327, 328/95-16. The licensee's investigation determined that the relay (a Qualitrol Corporation Series 900 model) had a distended nonorificed bellows. Additional testing identified several other Qualitrol Corporation Series 900 model relays which exhibited the same problem.

The licensee's corrective actions included disabling Qualitrol Corporation Series 900 model relays on the main bank transformers; disabling this type of relay on other transformers, or replacing the relays with a sudden pressure relay of a different design. The licensee also issued an Operating Experience Note (OE 7384 I) to the Nuclear Network.

The licensee's investigation determined the cause of the bellows distention, and training to prevent recurrence of this problem was provided to the Customer Group. The licensee will replace the relays on the main transformers during the next scheduled RFO for each unit. Paragraph 3.6.4 of this report provides additional information regarding these relays.

As a part of this inspection activity, the inspector reviewed UFSAR 8.2.1.5, SWITCHYARD CONTROL AND RELAYING. No discrepancies were noted between the plant and the UFSAR. Based on this review, this LER was closed.

Within the areas inspected, one IFI was identified.

4.0 **ENGINEERING** (37750, 37551, 92903)

During the reporting period, the inspectors conducted periodic engineering evaluations for regional assessment of the effectiveness of the onsite engineering staff. Inspections were also performed to evaluate the effectiveness of the licensee's engineering organization to perform routine and reactive site activities, including the identification and resolution of technical issues and problems. The inspection included a review of the following activities.

4.1 PLANT MODIFICATIONS

4.1.1 DCN NO. M10825, GENERIC LETTER 89-10 PLANT MODIFICATIONS

Modifications of the following MOVs were intended to meet the requirements of GL 89-10. The scope of the plant modifications included: (1) establishing and implementing new switch settings for MOV 2-FCV-01-051, (2) replacing existing yoke and actuators for MOVs 2-FCV-63-093, and -094, and (3) replacing the existing yoke for MOV 2-FCV-74-001 with a stronger one. The scope also included replacing the existing yoke bolting for MOV 2-FCV-74-002 in addition to revising documentation to address replacement of the original yoke by WR A-117652. The inspector reviewed the plant modification and verified that the 10 CFR 50.59 Safety Evaluation was technically adequate. Procurement documents prepared for purchase of the actuator motor for MOVs 2-FCV-63-93 and -94 were also reviewed and verified to have included technical and quality requirements suitable for 10 CFR 50.49 application. The following documents were reviewed during this effort:

- Procurement Request No. SM-1171, Revision 1
- Limitorque Corporation Certificate of Compliance, dated March 29, 1995, Customer Purchase Order No. 86XNQ-838100 RD-1037215.
- EQ Binder No. SQNEQ-MOV-003-M-10825
- NE Calculation 2-FCV-63-093 (GL 89-10) Documentation of Design Basis Review Required Thrust/Torque Calculation and Valve and Actuator Capability Assessment for 2-FCV-63-093, Revision 0.

Based on the above reviews the inspector concluded that the DCN was technically adequate. The plant modification had incorporated technical and quality requirements suitable for the MOVs end use application. It also demonstrated the capability of the MOVs to perform their design function.

4.1.2 DCN NO. M11914A, TIME DELAY RELAY ON MAIN TRANSFORMER TRIP CIRCUIT

The scope of this plant modification included replacing existing Potter and Brumfield relays 546.6 and 546.7 with Agastat time delay relays for each main transformer bank. The design objective of the plant modification was to improve the reliability of BOP equipment by eliminating inadvertent unit trips caused by oil flow perturbations in the non-safety related transformer bank 2, phases A, B, C, and spare (2-OXF-241-VB02A, -VB02B, -VB02C, and -VB02S). A time delay on enabling the Bucholz relay was intended to alleviate this problem.

The inspector reviewed the plant modification and determined that the application of the 10 CFR 50.59 screening criteria had been adequately

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The inspector reviewed the plant modification and determined that the application of the 10 CFR 50.59 screening criteria had been adequately

applied. A 10 CFR 50.59 Safety Evaluation was not required to be performed for this plant modification. Procurement documents and logic changes were also reviewed and verified to be consistent with the design objective. No deficiencies were identified with this plant modification.

4.1.3 DCN NO. R11846, EHC PUMP REPLACEMENT

The scope of DCN R11846 involved rerouting EHC system piping and replacing the existing fixed displacement vane pumps with variable displacement pumps. The installation of variable displacement pumps were intended to reduce vibrations caused by frequent cycling of the existing pumps. Implementation of this plant modification will reduce overall vibrations of the EHC skid.

The inspector reviewed the plant modification and determined that the design change was a recommendation described in Westinghouse Availability Improvement Bulletin 9107 for enhancement of the EHC system. The plant modification was intended to be performed under contract with Westinghouse. The inspector did not identify any deficiencies with this plant modification package.

4.1.4 DCN NO. M11360A, TURBINE TRIP LOGIC FOR GENERATOR COOLING WATER DIFFERENTIAL PRESSURE AND DISCHARGE TEMPERATURE

The scope of this plant modification involved changing the generator stator cooling water differential pressure and discharge temperature trip logic from a one out of one to a two out of three logic configuration. The generator stator cooling water differential pressure is monitored by instrument 1-PDS-35-120B which initiates a turbine trip upon sensing a differential pressure of 19.5 psi decreasing. Temperature instrument 1-TS-35-104 currently monitors the stator cooling water discharge temperature. Upon detecting a temperature of 194 °F increasing, a turbine trip is generated.

The inspector reviewed the plant modification and determined that a 10 CFR 50.59 Safety Evaluation had been performed because of changes to UFSAR Figure 10.2.2-1. The plant modification involved non-safety related non-seismic instrumentation located in the turbine building. Based on review of the plant modification, the inspector verified that logic changes were consistent with the design objective. The hardware changes implemented by the licensee were intended to improve BOP equipment reliability and preclude inadvertent trip of the reactor which occurs when the reactor power is above the P9 set-point.

No deficiencies were identified with DCN No. M11360A.

4.1.5 DCN NO. M11730A, MODIFY ROD CONTROL SYSTEM

The NRC issued Information Notice 93-46, Potential Problems With Westinghouse Rod Control System and Inadvertent Withdrawal of a Single Rod Cluster Assembly, dated June 10, 1993, to alert licensees to the

potential for an inadvertent withdrawal of one or more rod control cluster assemblies in Westinghouse plants in response to an insert signal. On June 21, 1993, GL 93-04, Rod Control System Failure and Withdrawal of Rod Control Cluster Assemblies, 10 CFR 50.54(f), was issued by the NRC to provide additional information and to advise licensees that the NRC will use information in the GL to assess licensee's compliance with the plant specific licensing basis regarding single failures in the rod control system. Westinghouse Owners Group (WOG) Rod Control System Evaluation Program identified options to be implemented in response to GL 93-04. The WOG submitted WCAP-13864, Revision 1, by letter dated July 12, 1994 to the NRC. Related documents were also submitted to the NRC which performed an evaluation and issued Safety Evaluation Report (SER) Relating to Topical WCAP-13864, Revision 1, Rod Control System Evaluation Program and Related Documents (TAC No. M88305). The NRC staff concluded that the WOG proposed hardware modification and additional surveillance tests at the beginning of each cycle was an acceptable resolution to the concerns raised in GL 93-04.

TVA implemented the WOG recommendations by development of DCN No. M11445A, Revision 0, that was installed for Unit 1 during the cycle 7 RFO. Plant modification DCN No. M11730A, Revision 0, was prepared for Unit 2 and will be installed during the next scheduled RFO. The scope of the plant modification included adding a suppression diode across the add coil and the subtract coil for each step counter and relocating existing diodes on the slave cycler decoder printed circuit boards. Repositioning the diodes on the solid state rod control system logic cabinet slave cycle decoder cards would be performed under contract by Westinghouse in order to implement the new current order timing.

The inspector reviewed Westinghouse Electric Corporation Nuclear Safety Evaluation Checklist Rod Control System Logic Cabinet/CRDM Timing Change, GENCL-94-005, Revision 0, contained in the plant modification package. The results of this review revealed that Westinghouse had determined from a failure assessment that modification of the rod control system had created some new failure modes. The Westinghouse 10 CFR 50.59 Safety Evaluation did not address how these new failure modes would be resolved; and neither did the Engineering Safety Assessment performed by TVA. Specifically, the statement in TVA's safety assessment located in item 22 of responses to checklist item, Equipment Failure Modes, was determined to be incorrect, in that it stated there were no new failure modes.

In discussions with TVA management concerning this issue, the inspector determined that TVA had failed to make provisions for fully implementing the recommended surveillance tests identified in WCAP-13864, Revision 1, which had been accepted by the NRC in the related SER. Either combination of surveillance tests listed below were required to be performed for identifying component failures associated with the new failure modes identified by Westinghouse.

(1) Slave Cycle Current Order Test along with Coil Current Test.
(2) Power Cabinet V Reference Test along with Coil Current Test.

TVA indicated that they will correct the above deficiency by responding to NRC's letter to Mr. Oliver Kingsley, Jr., dated December 9, 1994, Subject: Response to GL 93-04, Rod Control System Failure and Withdrawal of Rod Cluster Assemblies 10 CFR 50.54(f), and identify which combination of surveillance tests will be performed for Unit 1. Additionally, PER No. SQ960677PER, Level C, was written on March 13, 1996, to document this deficiency and initiate corrective action. Lack of clarity in TVA's Safety Assessment concerning the new failure modes of the rod control system and requirements for performing recommended surveillance tests was identified as URI 327, 328/96-02-04, omission of surveillance tests for Rod Control System, pending NRC review to determine the significance of the deficiency.

The inspector concluded that the DCNs reviewed were technically adequate and had been prepared in accordance with the requirements of the ANSI N45.2.11-1974 design control program. Examples of BOP equipment problems that had the potential to impact plant operations were corrected by DCNs M11914A and M11360A. Safety Assessments performed for non-safety related modifications to determine if the requirements of 10 CFR 50.59 applied were thorough and were performed in an adequate manner. Safety Evaluations performed in accordance with the requirements of 10 CFR 50.59 were also considered technically adequate. The licensee's safety assessment for the rod control system modifications failed to address new failure modes that was created by the hardware changes. The Safety Assessment Checklist, Appendix G, Item 22, was incorrectly answered. This error contributed to the failure to identify the combination of surveillance tests that were required to be performed at the beginning of each cycle. The underlying root cause of this deficiency, however, was inadequate interface controls between TVA and the WOG, in that information from the WOG required by TVA to develop corrective actions for concerns identified in GL 93-04 was never properly implemented for DCN No. M11445A.

4.2 OPERABILITY DETERMINATIONS

The inspectors reviewed a selected sample of PERs written for degraded or non-conforming equipment/components which had the potential to affect Unit operation. The PERs were reviewed to verify the licensee had made a prompt determination of operability with a timeliness commensurate with the potential safety significance of the issue. The operability determinations reviewed were also verified to have addressed all safety concerns. Additionally, they were reviewed to ensure they provided a reasonable expectation that the degraded or non-conforming equipment/component was operable, and objective evidence used in the determination process supported that expectation. Corrective action plans developed pursuant to the operability determinations were reviewed for adequate root cause analysis, extent of condition evaluation, and recurrence controls. The following PERs were reviewed during this inspection to verify compliance with the requirements of SSP 3.4, Appendix E, OPERABILITY/REPORTABILITY DETERMINATIONS, Revision 14.

- PER No. SQ960110PER, Level B, Load tap changers for common station service transformer B is hunting and relay cannot be adjusted to correct problem and maintain voltage within the design limit.

- PER No. SQ960266PER, Level B, Red light for 86 G/A relay blew causing lockout relay to actuate making DG 2A-A inoperable. This circuit and its effect on all four DGs needs to be looked at.

- PER No. SQ960290PER, Level B, Occurrence of LCP Lockup in Protection Set IV, Rack 13.

- PER No. SQ960220PER, Level B, The stator bridge readings for the 1B-B Diesel Generator failed to meet acceptance criteria (0.05434 ohms to 0.06006 ohms).

- PER No. SQ960057PER, Level B, Protection Set IV trouble alarms, high-high level and low-low level for all four steam generator came in and cleared repeatedly and level instrumentation began swinging.

- PER No. SQ950029PER, Level B, Two dislodged anchors on a RHR system support.

- PER No. SQ951928PER, Level B, Failure of the turbine driven auxiliary feedwater pump to trip in overspeed during an uncoupled test run.

- PER No. SQ951630PER, Level B, Weld indications found in the top deck area of two DGs.

- PER No. SQ960368PER, Level B, Commercial grade dedication of safety related valves.

Operability evaluations prepared for the PERs were reviewed and determined to be technically adequate. Equipment failures were identified as the root causes for degraded/non-conforming conditions identified on PER Nos. SQ960290PER, SQ960266PER, and SQ960057PER. Replacement of the defective part/component corrected the degraded/non-conforming conditions. The underlying root cause of PER No. SQ960110PER was inaccuracy of the ASEA Brown-Boveri type SVR control relay which operated the load tap changer to maintain the required voltage. A plant modification was proposed for replacing this relay with one having the accuracy requirements specified in the set point and scaling documents. PER No. SQ960220PER was determined to have stator bridge ohmic readings different from values obtained during factory tests by the original equipment manufacturer. The underlying root cause of this problem was the different test methodology used by the licensee. Additional test leads used by the licensee introduced errors in the stator bridge readings. The licensee is reviewing their test methodology with the

intention of revising it to more closely model that used by the equipment manufacturer during factory tests. The inspector did not identify any deficiencies with the operability evaluations reviewed.

Based on additional reviews of operability evaluations for PER No. SQ950029PER, the inspector verified that the RHR system support had a seismic evaluation performed which indicated that the support would be able to perform its design function. In the case of PER No. SQ951928PER involving the TDAFP, the wrong instrumentation had been used for the test. After this error was recognized and corrected the test was successfully completed. A procedure change initiated to identify the correct instrumentation was determined to be adequate for recurrence control. Deficiencies documented on PER No. SQ951630PER involving weld indications on one of the diesel generators (a problem originally identified at Watts Bar) were examined by the inspector. Based on discussions with the cognizant welding engineer and review of the operability evaluation, the PER evaluation appears to be correct. With regard to PER No. SQ960368PER concerning commercial dedication of safety relief valves, a hold tag has been placed on the valves in the warehouse until the problem can be resolved. None of the valves have been issued for installation. No problems were identified with the licensee's operability determinations for the PERs reviewed.

The inspector concluded that the operability determinations were performed in accordance with the requirements delineated in procedure SSP 3.4, Appendix E. No deficiencies were identified.

4.3 PROBLEM EVALUATION REPORTS

From the list of all PERs written in 1995 and 1996 and assigned to NE for evaluation, the inspector selected a short list for review. The short list included Level A and B PERs, which were the most safety significant. Several Level C PERs were selected to make a total sample size that was balanced in the following characteristics:

- About equal percentage in open and closed status.
- Included examples from several basic areas such as construction, design, procurement, 10 CFR 21 reports, UFSAR deviations, personnel error, etc.
- Included evaluations performed by six different subgroups within NE.
- Included a fairly high percentage involving operability evaluations.

The PERs were reviewed with regard to several attributes: the most important being that the evaluations and corrective actions were complete and thorough. The inspector concluded that this criterion had

been met. No significant weaknesses in this area of review were identified.

The inspector performed additional evaluations of the following PERs to determine if they had been properly dispositioned and that correct root causes had been identified and adequate corrective actions were taken:

- PER No. SQ951449PER concerning the fatigue failure of a check valve shaft in the keyway outside the valve body.
- PER No. SQ951485PER concerning circumferential cracking on a 16 inch feedwater heater pipe.
- PER No. SQ952017PER concerning an adverse trend in tube plugging of the 1-B containment spray heat exchanger.
- PER No. SQ952310PER concerning leakage of an ERCW butt weld (due to microbiological influenced corrosion) not being dispositioned within seven days (procedural requirement).
- PER No. SQ952340PER concerning a steam leak in the turbine building.
- PER No. SQ960180PER concerning a pin hole leak in a two-inch diameter carbon steel ERCW line.
- PER No. SQ960156PER concerning a pin hole leak in the 2A-2B seal injection pump.
- PER No. SQ960216PER concerning rupture of safety related one-half inch stainless steel pressure sensing lines for screen wash pumps.

The inspector discussed root cause evaluations and corrective actions for the PERs. In-depth discussions were held with the metallurgical and welding engineers on the problems identified by the PERs in these areas. Their conclusions for these PERs were complete. During a tour of the Central Laboratories (the support laboratory for Sequoyah and other TVA sites), the inspector examined some of the actual failed parts for PER Nos. SQ950029PER and SQ9600216PER. The Central Laboratories have excellent equipment for performing their metallurgical analyses. No problems were identified by the inspector.

4.4 MOTOR CONTROL CENTERS

The licensee was in the process of replacing the original motor control center starters (i.e. the entire removable compartments) with new equipment of a different design. The vendor for the new equipment was Farwell and Hendricks of Cincinnati, Ohio. The inspector reviewed several of the documents related to the purchasing of this equipment to

ascertain whether it had been purchased in accordance with 10 CFR 50, Appendix B, requirements. The documents reviewed were:

- TVA Surveillance Report 95S-19 on Farwell and Hendricks, dated August 23, 1995.
- Farwell and Hendricks Environmental Qualification Report No. 62042.1.
- Procurement request SE-2057 and Specification SS-E6.3.01.
- Vendor Audit Report (NUPIC) on Farwell and Hendricks, for an inspection conducted November 16 - 18, 1993.

The original equipment had been manufactured/assembled by Arrow-Hart. Farwell and Hendricks fabricated the steel enclosures for the new starters from Arrow-Hart drawings to be compatible with the existing motor control center frame and bus structure. They purchased and assembled the various components, such as Square D contactors and overload relays, General Electric breakers, etc. Farwell and Hendricks had an Appendix B program for supplying and qualifying safety-related motor control centers. Therefore, the equipment was purchased "safety-related" by the licensee. The inspector examined samples of the new equipment installed in the motor control centers with the back and front covers removed. The inspector interviewed the cognizant engineers as to what problems had been detected in the new equipment during the onsite commissioning tests.

The inspector concluded that the procurement of the new motor control center equipment was conducted in accordance with 10 CFR 50, Appendix B, requirements.

While performing the inspections which are discussed in paragraphs 4.1 through 4.4 of this report, the inspectors reviewed the applicable portions of the UFSAR related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

4.5 REVIEW OF SPENT FUEL POOL CURRENT LICENSING BASIS

Since 1992, the staff has been reviewing licensing and design issues associated with spent fuel storage pool safety at operating nuclear power plants. The staff has an action plan in place, sponsored by the DSSA, which provides for a thorough and methodical review of spent fuel storage pool safety issues. Upon completion of the action plan, the staff will determine if any new regulatory requirements need to be implemented and will pursue backfit activities as appropriate.

The issues under review include the reliability of spent fuel decay heat removal systems under a variety of normal and off-normal plant conditions. The inclusion of these issues in the action plan stems from

the staff's review of a 10 CFR Part 21 report filed in November 1992 which detailed potential deficiencies in the design of spent fuel pool cooling systems at the Susquehanna Steam Electric Station.

In addition, the staff is reviewing core offload practices and irradiated fuel decay heat management during refueling outages. Concerns in this area stem from a number of design and licensing problems discovered at the Millstone Unit 1 nuclear power plant in the fall of 1995. The problems found at Millstone 1 triggered increased concern about whether all operating reactors were conducting refueling core offload activities in a manner that was consistent with the design assumptions described in the current licensing basis for the facility.

To facilitate completion of the DSSA Action Plan and to address concerns about refueling practices highlighted by the Millstone review, project managers of all operating facilities were tasked to survey the design and licensing basis for the facility as it pertains to spent fuel storage pools. This project requires that project managers perform a detailed review of the plant's current licensing basis and design basis. In addition, project managers will need to determine, through site visits and interaction with the resident inspector and regional staff, how the licensee ensures that its operating practice is consistent with the CLB. Project managers are expected to pursue resolution of discrepancies between operating practices and licensing basis requirements. Any concerns about the adequacy of the existing licensing basis will be addressed by DSSA as part of the action plan.

On March 5 and 6, 1996, David E. LaBarge, Senior Project Manager, NRR visited the Sequoyah site to gather plant-specific information needed to review plant licensing basis requirements of the Spent Fuel Pool Cooling System. Discussions were held with J. Smith, Licensing Manager; W. Ludwig, Licensing Engineer; and H. Koehler, System Engineer.

As a result of the initial phase of the study, the following observations were made to the licensee at a meeting held on March 6, 1996:

1. There is no alarm in the MCR that will indicate the loss of SFP cooling although not required by the UFSAR. Therefore, loss would be indicated by high fuel pool temperature, low water level, or high radiation alarms.

2. There is no procedure for checking SFP heat load against the capacity of the system although not required by the UFSAR. This could be used to determine the potential temperature rise should the SFP cooling pump(s) be lost and would be especially useful in the event of a loss of site power, since the SFP cooling pumps do not restart upon restoration of power.

3. Engineering analyses are supplied to the site from the Corporate office that relates SFP storage parameters for the four design scenarios, and another that relates SFP total MW stored in the

pool over various days in the outage. However, this information has not been summarized for operations use.

4. At 180 °F the SFP pumps must be secured due to cavitation concerns. This may not have been highlighted to the Operators, with the result that there may be significant reluctance to shutdown the only method available that will prevent boiling in the pool.

   In addition, Scenario 2.b of the rerack submittal contains an analysis of the consequences of operation of only one SFP cooling loop under certain, specified, loading conditions in the SFP. The analysis results in the SFP temperature reaching 183 °F. Since the SFP cooling pumps must be shutdown before this temperature is reached, the question was raised as to the ability of the system to handle the scenario. [The initial rerack submittal indicated the maximum temperature would be 177 °F. This, therefore, represents new information.] The licensee reevaluated the 180 °F temperature limit and determined that pump cavitation would not be a problem until temperature reached 195 °F, and indicated that procedures would be revised.

5. On September 9, 1995, at 1:00 am, insertion of all control rods was completed to start the Unit 1, Cycle 7 refueling outage. On September 19, 1995, at 8:00 am, the first fuel assembly was removed from the core (10.3 days). The original rerack submittal assumed that the entire core from one reactor is transferred to the pool after 12 days of decay in the reactor. There appeared to be an inconsistency between the design-basis analysis and actual practice. Upon discussion with the licensee, it was determined that, in accordance with the reanalysis performed by the licensee during review by the staff of the rerack submittal, the technical specification limit of 100 hours was used. The results were found to be acceptable by the staff when the amendment was issued. In addition, the initial fuel inventory criteria used in the analysis did not exist. Therefore, the existing heat load was considerably less than that assumed in the analysis. Therefore, the issue was resolved.

6. The existing UFSAR indicates that, upon loss of SFP cooling capability, the water loss by evaporation would be about 55 gpm. It also specifies the various systems that can be used to add water to the pool, one being the fire protection system. The UFSAR also indicates that the fire protection hoses are capable of supplying more than 55 gpm.

The licensee had identified this error. An evaluation had recently been performed by the licensee that will be incorporated into the next UFSAR update. It indicates that the evaporation rate would be approximately 103 gpm. All makeup systems have been evaluated and shown to be capable of supplying this makeup water flow rate.

In addition to the evaluation performed by the NRR Project Manager, the resident inspectors reviewed the UFSAR Sections concerning the SFP system. Specific attention was directed toward the UFSAR description of what is the normal core offload practice (full or partial core offload) during a refueling outage and whether the SFP system is designed for "single failure" with a full core offload.

UFSAR Section 9.1.4.2.1, REFUELING DESCRIPTION, PHASE III-FUEL HANDLING, states that "A complete core offload, core component shuffle in the spent fuel pit, and core reload are typically performed." UFSAR Section 9.1.3.1.1, SPENT FUEL PIT COOLING, states that "The system design incorporates two trains of equipment (plus a spare pump capable of operation in either train), either train being capable of removing more than 50% of the design heat load at design conditions." UFSAR Section 9.1.3.3.2, SAFETY EVALUATION, AVAILABILITY AND RELIABILITY, states that "In the event of failure of one spent fuel pit pump, the backup pump would be aligned and operated. In the event of loss of cooling to one spent fuel pit heat exchanger, cooling of spent fuel pit water could be maintained by the remaining equipment; however, the reduced heat removal capacity would result in elevation of the equilibrium spent fuel pit water temperature to a higher but acceptable temperature."

The resident inspectors concluded that the current UFSAR accurately describes the licensee's practice of performing a complete core offload each refueling outage and that the SFP system is designed for a "single failure."

As noted above in item 6 of the Project Manager's evaluation, UFSAR Section 9.1.3.3.2 currently states that under certain conditions the SFP water loss by vaporization would be about 55 gpm. A recent licensee evaluation determined that the actual vaporization would be approximately 103 gpm. Corrected data will be included in the next revision of the UFSAR which will be submitted by January 1, 1997. Several additional SFP UFSAR changes will be made in the January 1997 revision which will incorporate the analysis performed for the SFP rerack project which was completed in 1995. The inspectors determined the update schedule was consistent with the requirements of 10 CFR 50.71(e)(4).

4.6 REVIEW OF UNIT 1 PLANT STATUS DURING RESTART

During a walkdown of the Unit 1 secondary plant on March 11, 1996, the inspector observed installation of a new sampling system to the condenser hotwell pumps' suction lines. Unit 1 was in MODE 4 at the time. The inspector questioned operations relating to configuration of the new sample system and requested feedback. Later on March 11, operations wrote PER No. SQ960654PER to address the inspector's question. The PER stated that the new sample system was aligned to the hotwell pumps' suction lines (root valves open). However, the sample system valves were not under configuration control because the system had not been turned over to the chemistry group.

The inspector conducted additional followup of this issue on March 18, 1996. During a plant tour, the inspector noted configuration was essentially the same as observed on March 11, 1996. Unit 1 was operating at full power at this time. The inspector questioned operations regarding the PER and questioned how configuration control was being maintained on a system that had not been turned over. Operations showed the inspector a copy of the hold order that was cleared in October 1995, and also a copy of the system status logs that configured the root valves for this portion of the sample system. Later in the day, operations tagged shut the root valves associated with the sample system in order to assure positive configuration control was being maintained for the condensate system. Clearance No. 1-HO-96-1537 was implemented tagging shut the six Unit 1 root valves associated with this issue. The inspector verified the valves in question were tagged shut during a plant walkdown.

The inspector reviewed SSP-9.3, PLANT MODIFICATIONS AND DESIGN CHANGE CONTROL, Revision 14. The purpose of the SSP was to define the responsibilities and requirements for the development, implementation, and closure of design changes and modifications to systems, components, and structures at Sequoyah Nuclear Plant. Section 5.3.2 of the SSP stated that field engineers will remain on clearances until equipment can be returned to service unconditionally (i.e. procedure reviews, primary drawing updates, RTO, etc.), except as noted in Section 5.4.3. Section 5.4.3 of the SSP allowed for lifting of the hold order for performance of PMT that required the component or system to be in service. If after performance of the PMT, the equipment <u>cannot</u> be returned to service unconditionally, (drawings and procedures updated, RTO walkdowns performed, etc.) the cognizant engineer shall insure operations issues a clearance to indicate that an open issue exists. Based on this review, the inspector considered the licensee failed to follow the requirements of the SSP regarding the sample system which was connected to the Unit 1 condensate system.

On March 20, 1996, the inspector met with licensee personnel from operations, modifications, licensing, and chemistry to discuss these findings. The inspector questioned the licensee regarding completeness of the modification and required controls if a modification is not complete. The inspector was informed that the modification was essentially completed with the exception of testing of the pump. The licensee also identified that all procedures for configuration control of this portion of the sample system had not been completed. The inspector questioned the licensee regarding extent of condition of this type of issue in other areas of the plant. During the next two days, the licensee began an extent of condition review and identified several other modifications being worked without proper clearance control. On March 22, 1996, the MRC was briefed on the status of the review. They were informed that several problems associated with proper clearance control of incomplete modifications were identified. Six items were specifically debriefed in addition to the inspector's issue.

Modification control deficiencies involved the following safety-related or important to safety systems:

- Unit 1 cold leg accumulators sample system modification.
- Steam generator blowdown radiation monitor 1-RE-90-124 modification.
- Unit 1 boric acid blender sample system modification.

In addition, several other modifications on nonsafety-related plant equipment were identified that lacked proper clearance control. Based on these additional findings, the inspector determined the licensee did not control modifications as required by procedure. Failure to control implementation of plant modifications as required by SSP-9.3 is identified as VIO 327, 328/96-02-05.

The inspector concluded that after March 20, 1996, the licensee aggressively conducted an extent of condition review of the issue, and identified additional deficiencies relating to control of incomplete modifications in the plant. However, prior to this date, the licensee's sensitivity to the issue was not apparent.

4.7 FOLLOWUP

(Closed) Violation 327,328/95-13-01, Inadequate Implementation of Corrective Action for Arrow-Hart Motor Starter Contactors. The originally installed motor control centers had experienced a buildup of film on the auxiliary contacts used for interlocking in reversing contactors. The film built up on these particular contacts because they interrupt very low currents, and contaminants were not burned off at each operation. The film may have been lubricant, applied to offset sticking of the contact mechanism, which had migrated to the contact surface. The film caused high contact resistance, which caused the control circuits to fail. As a compensatory measure, the licensee had issued a Standing Order to require a resistance check on contacts each time the associated load was operated. An NRC inspector had identified that the Standing Order had not always been carried out, which contributed to the subsequent failure of safety-related valves to operate on demand. A violation was issued for this problem. In their response to the violation, the licensee committed to several corrective actions. The inspector verified that these corrective actions had been implemented. The inspector went to the MCR and reviewed Standing Order 95-77, which was in effect from November 21, 1995, through November 21, 1996. The Standing Order required the placement of a sticker on each MCR handswitch upon manipulation of a valve. The sticker would be removed once maintenance personnel had been notified to perform the resistance check on the auxiliary contacts. The inspector reviewed the log for March 8, 1996, maintained in the MCR to track the valve operations, resistance checks and results. The inspector noted that MCR personnel were knowledgeable of the motor control center contact problem

and the importance of the resistance checks. The inspector concluded that the corrective actions stated in the response to the violation were implemented. Violation 95-13-01 was closed.

(Closed) IFI 327,328/94-28-01, Acceptability of In-house Test Performed on 110 Vac Contactors. The issue involved the fact that the control circuit voltage calculations incorporated the results of in-house testing on contactors. The testing was conducted to establish a new pick-up voltage rating. The inspector had identified weaknesses in the test procedure. The inspector's review of the calculations had concluded that substantial conservatism and margin was incorporated in the calculations, which were bounding type calculations. The inspector had concluded, based on preliminary review, the calculations could probably be revised to show that adequate voltage existed to meet the equipment published ratings.

Since the time this issue was identified, the calculation in question, Calculation SQN-APS-010, Class 1E Motor Control Center Circuit Undervoltage Calculation, has been revised four times. At the time of this inspection, the calculation was on Revision 18. The inspector reviewed these revisions, and observed that they reflected the fact that many MCC starters were replaced with new equipment of a different design. Also, improved bus voltages had been calculated by updated overall system calculations. In addition, certain loads in parallel with the starter contactors were changed from inrush to steady state, which was consistent with actual circuit operation. The criterion for pick-up voltage of an Arrow-Hart size 1 starter was changed from 82.5 V to 93.5 V. The calculation concluded that all the safety-related contactors received adequate voltage within the published rating, and the inspector agreed with the conclusion. The inspector considered the issue resolved, and Inspector Follow-up Item 94-28-01 was closed.

(Closed) IFI 327,328/93-35-01, PVC Cables Exuding Plasticizer. PER No. SQ931556PER was written to resolve concerns related to the fact that PVC jackets on electric cables were exuding the plasticizer. It is well known among industry cable specialist that PVC insulated or jacketed cable may exude plasticizer compound as part of the aging process.

At Sequoyah, the problem was restricted to cable jackets (insulation was not PVC) of cables run in raceways. It applied to medium-voltage, low-voltage, control and instrumentation cables. There were two concerns associated with the leaking plasticizer:

- It could attract contaminants and create a leakage path on medium-voltage or 480 V cables.

- It could flow into devices such as breakers or relays and put an insulative film on contacts or cause parts to stick.

The possibility for plasticizer coming in contact with a relay or breaker was minimized because the cable jackets were cut back at cable wireways, and did not come in proximity to devices.

The licensee conducted evaluations and inspections on the equipment. These were evaluated in previous NRC inspections as documented in NRC IR 327, 328/95-35, Section 3.4. The IFI was established to review the results of the longer term monitoring program and to assess the potential impact of the plasticizer on plant equipment.

Ten control points were identified to assess whether the phenomenon was continuing and, if so, at what rate. The chosen points were areas where the most plasticizer had been seen on the first round of inspections. After cleaning, the points were inspected in May 1994. Some plasticizer was seen, but in diminished quantity. Another inspection was conducted in September 1994. This date was chosen to assess the effects of summer heat on the phenomenon. Very little plasticizer was observed.

SSP-6.25, MAINTENANCE MANAGEMENT SYSTEM PERFORMANCE OF WORK ORDERS, Revision 8, specifies that inspections of equipment shall include looking for plasticizer. It gives instructions on what to do when plasticizer is observed.

The inspector verified by examining samples of the motor control center equipment, which had been removed as part of the upgrade project described above, that the internal wiring was not PVC, and plasticizer could not be observed on the components.

The inspector concluded that, while the plasticizer problem was an ongoing issue, the licensee had control of the problem. IFI 327,328/93-35-01 was closed.

Within the areas inspected, one violation, one URI, and one IFI were identified.

5.0 **PLANT SUPPORT** (64704 and 71750)

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 FIRE PROTECTION PROGRAM (64704)

The inspector evaluated the adequacy and implementation of TVA's approved Fire Protection Program at Sequoyah with the exception of the specific requirements of 10 CFR 50 Appendix R, Sections III, G, J. L. and O (fire protection of safe shutdown capability, emergency lighting, alternative and dedicated shutdown capability, and oil collection system for reactor coolant pumps).

The current Fire Protection Program is described in UFSAR Section 9.5.1 and in a document dated October 23, 1979, which was TVA's response to the NRC's questions on the fire protection review of Sequoyah's Fire Protection Program. TVA was preparing a revision to the UFSAR and a new document to describe the Fire Protection Program at Sequoyah. This new document was approximately 75% complete and will contain the Sequoyah Fire Protection Plan and the operability and surveillance requirements for the fire protection features at Sequoyah. This data is scheduled to be sent to the NRC on August 3, 1996, along with an amendment to remove the operability and surveillance test requirements for the fire protection features from the TS. The new fire protection document will be modeled after the Watts Bar Fire Protection Program document and will be an improvement over the existing documentation.

5.1.1 FIRE PROTECTION ADMINISTRATIVE PROCEDURES

The general responsibilities and programmatic control of the site's Fire Protection Program are described by SSP-12.15, FIRE PROTECTION PLAN, Revision 13. The following fire protection instructions and attachments to SSP-12.15 were the procedures for implementing the principle areas of the program:

- FPI-0101, CONTROL OF IGNITION SOURCES, Revision 0
- FPI-0180, COMPENSATORY FIRE WATCH RESPONSIBILITIES AND CONTROL, Revision 0
- SSP-12.15, Appendix B, WORK ACTIVITIES
- SSP-12.15, Appendix C, IMPAIRMENTS
- SSP-12.15, Appendix E, CONTROL OF COMBUSTIBLES
- SSP-12.15, Appendix F, EMERGENCY RESPONSE
- SSP-12.15, Appendix H, FIRE PROTECTION TRAINING
- SSP-12.15, Appendix I, PREFIRE PLANS
- SSP-12.15, Appendix K, INSPECTION, TESTING AND MAINTENANCE

The inspector reviewed these procedures and found they met the NRC guidelines and were adequate.

Procedure SSP-9.3, PLANT MODIFICATIONS AND DESIGN CHANGE CONTROL, Revision 13, was reviewed and found to contain sufficient guidance and checklists to assure that changes to the plant which could affect the fire protection systems or Appendix R cable separations could be identified.

5.1.2 IMPLEMENTATION OF FIRE PROTECTION PROCEDURES

Plant tours were made by the inspector to review the implementation of the fire protection procedures.

Two modifications, WRC 127153 and WRC 340629, involving hot work activities were reviewed and found to be properly following the requirements of FPI-0101. These operations were being performed on 690' elevation in Unit 2 at column line A13 - T and in the penetration piping room respectively. The inspector interviewed the fire watch for these activities and found they were trained and understood the duties and responsibilities of a fire watch.

The plant areas containing the following transient fire load permits addressed by SSP-12.15, Appendix E, CONTROL OF COMBUSTIBLES, were inspected:

- TFL-95-0038, flammable equipment locker, auxiliary building, 669' elevation, Room A-31
- TFL-95-0087, miscellaneous storage, auxiliary building, 669' elevation, Room A-31
- TFL-96-0003, flammable equipment locker, auxiliary building, 669' elevation, Room A-31
- TFL-95-0254, radcon dressout clothing, auxiliary building, 690' elevation, column lines A4 to A6
- TFL-96-0013, flammable equipment locker, auxiliary building, 690' elevation, east decon collection tank room
- TFL-96-0034, canvas floor covering for refueling floor
- TFL-96-0038, fire retardant lumber for scaffolding, auxiliary building, 669' elevation, Unit 2 penetration room

With the exception of permit Nos. TFL-96-0034 and TFL-96-0038, the permits for the control and identification of transient combustibles were actually issued for areas which appeared to be used permanently for the storage of combustibles. This did not meet the intent of controlling transient combustible fire loads. The installed fire protection features for most of these areas, except for Room A-31 on 669' elevation of the auxiliary building, were acceptable for the storage of the combustibles identified by the transient fire load permit. However, Room A-31 was not provided with fire detection or fire suppression coverage as is normally provided for this type occupancy. This discrepancy was previously identified by TVA during an audit of the fire protection program. Industry practice is for areas of the plant routinely used for the storage of combustibles to be provided with fire protection features appropriate for the hazards involved. TVA had

previously issued PER No. SQ950428PER to evaluate this discrepancy and implement the appropriate corrective action. Resolution of this item will be reviewed during a subsequent NRC inspection. This is identified as an example of Inspector Follow-up Item 327, 328/96-02-06, Evaluation of Corrective Action Taken on TVA's Fire Protection Audit Findings.

The inspector noted several fire protection system and fire barrier discrepancies during the plant tour. TVA informed the inspector that these items had previously been identified and were listed in the fire protection impairment log. The impairment log was reviewed and these items were included in the log; however the log included a number of discrepancies which had exceeded the expiration time permitted by SSP-12.15, Appendix C, IMPAIRMENTS. The inspector reviewed a sample of these impairments and verified that either a special report or an LER had been issued on these impairments as follows:

IMPAIRMENT NO.	PER NO.	REPORT TYPE & NO.
TS94P0458, Fire Barrier Seal	SQ940487PER	Special Report 94-08
TS94P0554, Fire Barrier Seal	SQ940466PER	N/A
TS95P0169, Fire Barrier Seal	SQ950261PER	Special Report 95-03
TS95P0475 THRU 95P0489, Fire Barrier Seals	SQ930547PER	LER 93-027
TS95P0776 & 95P0777, Fire Doors	SQ950349PER	Special Report 95-03
TS92A164, Missing Sprinkler Line	SQ910311PER	N/A
TS92A272, Fire Detection	SQ920225PER	Special Report 92-06
TS95A080, Fire Detection	SQ952294PER	LER 95-018

The two impairments which were not reported to the NRC by either a special report or an LER were evaluated by TVA. These items were determined not to be reportable. The items resulted in the barriers being in degraded conditions but did not render the fire barriers inoperable. The inspector considered TVA's action for these two items to be appropriate.

To compensate for the fire protection system impairments, TVA included these areas into the roving fire watch patrol. The fire watch patrol program at Sequoyah had been in place for several years and met the TS requirements for degraded fire protection features.

During the plant tours, the inspector reviewed the fire detection and suppression systems and noted that these systems were operable and, based on the equipment reviewed, were adequately maintained. The inspector used the valve list in SSP-12.15, Appendix C, IMPAIRMENTS, to locate and identify the automatic sprinkler systems required to be operable by the TS. During this review, the inspector noted a procedure weakness in that several valves listed in Appendix C had different numbers than the identification tags on the valves. The licensee promptly issued PER No. SQ960431PER to review this discrepancy, to determine the correct valve numbers and the required correction actions. This was a procedure weakness.

The inspector did not inspect or evaluate the existing Thermo-Lag fire barriers installed on the electrical raceways at Sequoyah. These fire barriers had been declared inoperable. TVA had included the areas in which these fire barriers were installed into the fire watch program as required by the TS.

5.1.3 SURVEILLANCE TESTING OF FIRE PROTECTION SYSTEMS

The surveillance inspections and tests and frequency required for the fire protection systems were listed by the TS. The inspector selected the following fire protection system components and reviewed the most current test, date of previous test, and date of next scheduled test to verify that these tests met the TS requirements:

TEST NO.	DESCRIPTION	SCHEDULE DATE	ACTUAL DATE
0-SI-FPU-26-167.M	Fire Header Valve Line-up Inspection (Monthly)	12/19/95 1/16/96 2/13/96	*12/21/95 *1/16/96 *2/15/96
0-PI-FPU-26-181.0	Fire Hose Hydrostatic Test - Annual (Exterior Hose)	12/6/93 11/6/94 10/2/95	12/29/93 *11/23/94 *10/7/95
0-SI-FPU-26-191.0	Fire Hose Station Inspection (18 Months)	11/14/92 5/18/94 N/A 5/22/97	11/15/92 *6/5/94 **11/16/95 N/A
0-SI-234.2	TS Fire Detectors for Panels 608, 609, 624 & 632 - 6 Months (Includes Sprinkler Valves 0-FCV-187 and 0-FCV-159)	7/25/95 1/23/96 7/23/96	8/3/95 *2/22/96 N/A
0-SI-EFT-39-237.0	Diesel Generator Building CO_2 Fire Protection Test (18 Months)	4/7/92 10/9/93 12/4/95	8/10/92 *6/25/94 N/A

NOTE: * Completed test package reviewed.

** This was a nonscheduled test for which credit was taken.

These tests were performed within the required frequency, or within the permitted grace period. The completed test procedures which were reviewed were satisfactory. However, during the performance of Surveillance 0-SI-EFT-39-237.0, on June 17, 1994, the belts to the CO_2 refrigeration unit were found to be cracked and in need of replacement. These belts were not replaced until January 31, 1995. The inspector considered this an excessive time to perform corrective maintenance on a component providing protection for safety related equipment, i.e. diesel generators.

The licensee informed the inspector that during the 1994 time period there was a very large number of outstanding corrective maintenance items. Following implementation of the 12 week rolling schedule in January 1995, the large backlog of maintenance items was reduced to a more manageable number. Currently, the licensee anticipates corrective maintenance on equipment to be completed in a more timely manner.

5.1.4 FIRE BRIGADE

Organization

The fire brigade is composed of an Incident Commander (an SRO, normally the Assistant Shift Operations Supervisor), Fire Brigade Leader (Fire Operations Foreman) and at least four fire brigade members. The fire brigade members were normally two AUOs and two fire operators. The plant operators work an eight hour shift per day and the fire operations group work a 12 hour shift per day. There were a total of 46 AUOs on the qualified fire brigade list. The inspector reviewed the operations shift assignment and noted that at least 6 brigade members were assigned to each of the 6 operations shifts and, except for shift E, there was a foreman and two fire operators assigned to each of the five fire operations shifts. Shift E had only a foreman and one fire operator who were on the fire brigade. Two fire operators had recently been disqualified for fire brigade duty. The licensee was maintaining the required manning by either the use of overtime by the fire operations group or using three AUOs for fire brigade duty per shift.

Training

The fire brigade's training consisted of quarterly classroom training, a week of classroom and field training at TVA's Fire Academy, and periodic fire brigade drills. The inspector reviewed the training records, fire brigade physical review records, and fire brigade drill participation, and verified that the training and medical reviews for the eligible fire brigade members were current.

Equipment

The fire brigade equipment, consisting of personnel turnout gear, self-contained breathing apparatus, smoke exhaust fans, hose nozzles and miscellaneous equipment, was stored primarily on the fire apparatus pumper parked in the fire equipment building north of the Unit 1 switchyard and in lockers on the 706' elevation of the service building. Each fire operation employee and most of the AUOs had been assigned fire fighting turnout gear; coat, pants, helmet, boots and gloves. The remaining AUOs had access to community fire fighting turnout gear which was stored on 706' elevation of the service building. A total of 14 self-contained breathing apparatus and 22 spare cylinders were available for fire brigade use and 12 self-contained breathing apparatus and 12 spare cylinders were provided in the MCR for use by the control room operators. The self-contained breathing apparatus cylinders were refilled by a compressor unit located in the fire equipment building. Additional spare cylinders were stored in the fire equipment house and were available for use, if needed. Also, the plant had mutual aid agreements with several municipal fire departments in the area which could provide additional equipment and supplies if required.

The fire apparatus was a Pierce/Arrow 1250 gpm pumper equipped with a 500 gallon water tank, 100 gallon foam tank, 600 feet of 5-inch hose, 800 feet of 3-inch hose, 200 feet of 2½-inch hose, 550 feet of 1¾-inch fire hose and miscellaneous equipment.

The fire brigade equipment was well maintained.

Fire Brigade Drill

The inspector witnessed a fire brigade drill conducted on February 29 as part of the quarterly emergency planning exercise. The drill involved a simulated transformer fire in the turbine building which also damaged the air compressors and supply line to the plant's instrument air system. The fire incident commander and brigade, consisting of the fire brigade leader and five fire brigade members (two fire operators and three AUOs) responded promptly to the simulated fire. The brigade responded in full turnout gear and self-contained breathing apparatus and simulated fire extinguishment by using a combination of fire hose water spray and dry chemical from a wheeled fire extinguisher unit. Additional personnel from security, health physics, and operations also responded. Maintenance personnel were contacted and were available if needed. Following the drill, the response personnel met to discuss the drill. The fire brigade response was satisfactory.

5.1.5 FIRE PROTECTION AUDITS

The inspector reviewed the most recent annual, biennial and triennial audits of the fire protection program and noted the date for the next

scheduled audits. The audit completion and scheduled dates were as follows:

DATES	TYPE OF AUDIT
7/13 - 9/11/92	Biennial and Triennial
6/6 - 7/15/94	Annual and Biennial
3/30 - 6/19/95	Annual and Triennial
3/96 Scheduled	Annual and Biennial
3/97 Scheduled	Annual
3/98 Scheduled	Annual, Biennial and Triennial

The 1992 audit identified two findings. Only one of these findings had been corrected. The open item involved the adequacy of emergency lighting and the preventative maintenance provided for these lighting units (correction scheduled for March 1996).

The 1994 audit identified five findings. One of these items had been corrected and one was resolved by a reevaluation. Corrective actions on the remaining three items had not been completed. These items were associated with: no action plan developed to restore 1500 fire barrier penetration seals requiring maintenance to operability (correction scheduled for August 1996); inadequate procedures for the evaluation and control of transient fire loads (correction scheduled for April 1996); and inadequate design control over fire barrier penetration seals (correction scheduled for August 1996).

The 1995 audit identified three findings and three weaknesses. Corrective actions for the three findings and one of the weaknesses had not been completed. The open items were: changes made to plant without following the design change or temporary alteration process (correction scheduled for April 1996); no inspections performed for the structural steel fire proofing supporting the floor above the cable spreading room; no testing performed on the cable spreading room CO_2 system since 1982 (corrective action is to remove this system from the room and revise the UFSAR accordingly - completion date had not been scheduled); and the Fire Hazard Analysis contained errors on fire loading and fire rating of fire barriers (correction scheduled for August 1996).

The inspector noted that TVA had not resolved the issues associated with the evaluation and control of transient combustible materials and maintaining the fire proofing material for the structural steel supporting the MCR floor above the cable spreading room. These items are identified as additional examples of IFI 327, 328/96-02-06, Evaluation of Corrective Action Taken On TVA's Fire Protection Audit

Findings. The 1995 audit stated that corrective actions on previous audit findings had not being corrected in a timely manner. As of June 19, 1995, five audit findings of the ten identified during the previous three audits were still outstanding.

The inspector found that the audits performed on the fire protection program were thorough and identified a number of problems, but the resolution of the identified problems was not accomplished in a timely manner. However, based on this inspection, for those items which involve operability concerns with the fire protection features listed in the TS, appropriate compensatory measures had been established for the fire protection deficiencies.

5.1.6 FIRE PROTECTION WATER SUPPLY MODIFICATION

The inspector reviewed DCNs M-08811-A, M-08812-A and M-08813-A which will provide a new high pressure fire protection water supply system, consisting of two 300,000 gallon supply tanks, two fire pumps, one diesel driven and motor driven, and a building to house the fire pumps. A potable water supply will be provided to the new system from the Hixson Utility District. The design requirements for these DCNs were based on Calculation SQN-026-D053 EPM-RSR-072994 which sized the capacity of the tanks and the new fire pumps. The raw service water loads supplied by the existing high pressure fire protection system will be removed from the fire protection system and supplied by another service water system. The existing system piping will be cleaned or replaced as necessary to improve the flow characteristics of the system. The new potable water supply system was intended to eliminate many of the problems which the system has experienced from the use of a non-potable water supply.

At the time of this inspection, the construction of the water supply main from the Hixson Utility District was practically complete but connection to the water tanks will not be until 1997. The construction and erection of the two water tanks was also almost complete. The inspector toured the tank construction site and noted that the tanks had been erected but had not been painted for protection from corrosion and erosion. The licensee informed the inspector that the tanks were to be painted during the Spring-Summer of 1996. Construction of the fire pump house will not begin until 1997, except the foundation for the building will be constructed during the Summer of 1996. The installation of the fire pumps was scheduled for mid-1997. Cleaning of the existing piping was scheduled for 1997. The new fire protection water system was scheduled to be operational in December 1997.

The new fire pumps, drivers, controllers and other components arrived at Sequoyah on October 13, 1995, and were moved into a storage warehouse within seven days. The inspector reviewed the storage of this equipment and noted that the equipment was stored in Warehouse 8, level "C" storage, i.e. fire resistance weather tight building providing protection from the elements and airborne contamination. The fire pump components were initially to be stored in a level "B" storage facility,

i.e. fire resistance weather tight building which provided protection from the effects of temperature extremes, humidity and vapors, and airborne contamination. The licensee's staff approved downgrading the storage requirements for these components from level "B" to level "C" storage, but did not provide a justification for this change. Furthermore, Warehouse 8 did not meet the requirements for level "C" storage since the building was not weather tight due to a missing wall on one side of the building.

The inspector reviewed the fire pump vendor's storage requirements and noted that TVA had neither incorporated the vendor's recommendations into appropriate procedures nor evaluated the recommendations for exception to address the storage and preventive maintenance required for the fire pumps, pump drivers and related components. A sample of some of the most obvious requirements and the actual storage conditions were as follows:

FIRE PUMP COMPONENT	VENDOR'S STORAGE REQUIREMENTS	ACTUAL STORAGE
Pump Controllers	Store in an area where temperature is maintained between 50 and 90 °F.	Stored in an unheated warehouse.
	Store in original container with plastic packing intact or place a desiccant inside the cabinet.	Plastic packing removed and no desiccant was placed inside the cabinet.
Pumps	Cover openings into pump with metal blank flanges secured by four bolts per flange.	Openings were covered with cardboard loosely held in place with tape. One opening was not covered.
	Cover pumps to prohibit accumulation of dirt and dust.	Pumps were not covered.
	Rotate pump shaft by hand each 4 to 6 weeks.	Pump shafts were not being rotated.

FIRE PUMP COMPONENT	VENDOR'S STORAGE REQUIREMENTS	ACTUAL STORAGE
Electric Motor for Pump	Prevent rodents, snakes or small animals from nesting or gaining access to the interior of the motor.	Motor was not protected to prevent rodent access into the interior of the motor.
	Prevent moisture accumulations by maintaining the bearing temperature 5 degrees above ambient.	Motor winding was not heated.
	Rotate motor shaft once per month.	Motor shaft was not being rotated once per month.
Diesel Engine for Pump	Fill cooling system with water and a rust inhibitor.	Cooling system was not filled with water.
	Fill crankcase with a 30 weight oil.	Oil level in crankcase was below the dip stick level.
	Cover engine to prevent accumulation of dust and dirt.	Engine was not covered.
	Store engine in a heated weather tight building.	Engine was stored in a warehouse that was neither weather tight nor heated.

When this storage discrepancy was identified by the inspector, the licensee promptly issue PER No. SQ960461PER to evaluate this problem and determine the appropriate corrective action.

SSP-10.3, HANDLING AND STORAGE OF MATERIALS AND SPARE PARTS, Section 3.2.2.B, requires the site engineering/procurement engineering group to establish storage/preventive maintenance requirements and provide appropriate engineering output documents delineating these requirements. SSP-10.3 also requires that engineering evaluations and engineering requirements will consider vendor recommendations. However, these requirements were not established. The failure to establish the storage and preventive maintenance requirements for the long term storage of the fire pump components in accordance with SSP-10.3 is identified as VIO 327, 328/96-02-07, Inadequate Storage and Maintenance of Fire Pumps and Fire Pump Components in Long Term Storage.

5.1.7 FIRE PROTECTION SPECIAL REPORTS

License Condition 2.H requires TVA to report to the NRC any violations of the operating license. The operating license for Unit 2 addresses the 10 CFR 50 Appendix R requirements for Sequoyah. Appendix R Section III.G requires redundant safety shutdown components to either:

1) be separated by a three hour fire rated barrier,

2) be separated by a horizontal distance of 20 feet with no intervening combustibles and with fire detection and fire suppression systems installed in the fire area, or

3) have one redundant train enclosed in a one hour fire rated barrier and with fire detection and automatic fire suppression systems installed in the fire area.

During 1989 and 1990, TVA identified two examples in which the Sequoyah plant did not meet these requirements. Two Special Reports were issued to report these issues to the NRC.

During this inspection, the inspector reviewed these events and the corrective action implemented to prevent recurrence.

Special Report 89-11

This report was sent to the NRC by letter dated October 17, 1989, and involved inadequate separation between electrical power cables to redundant RCS hot and cold leg temperature instrumentation loops. These loops fed the MCR RCS temperature recorders for both Units 1 and 2. TVA's analysis of this discrepancy found that these interactions did not render these circuits inoperable. In addition, the existing automatic fire suppression and fire detection systems installed in the interaction areas and the roving fire watch provided for these areas would have resulted in a fire in these areas being identified and appropriate corrective actions taken to ensure safe plant shutdown.

The inspector reviewed the following corrective actions taken on this report and verified that the required modifications had been completed:

- The cable interaction problems had been corrected by DCNs M-02217-A and M-01443-A for Unit 1 and M-02034-A for Unit 2. These DCNs were issued to reroute the required cables and install a one hour fire barrier around the applicable cables. The inspector reviewed the work completion forms for DCNs M-02217 and M-02034-A and verified that the work required by the DCNs had been completed.

- The electrical block diagram and drawing problems were corrected by revision to the block diagram and the Appendix R sketch drawings. The inspector verified that the revisions to the block diagrams which were accomplished by DCNs M-014994, M-01496-A and

M-01443 for Unit 1 and M-01494-A, M-01497-A, M-02034-A and M-01501-A for Unit 2 had been completed by reviewing the revised drawings and QC monitoring report Nos. QSQ-M-90-0416 and QSQ-M-90-0428.

Special Report 90-02

This report was sent to the NRC by letters dated February 9 and July 19, 1990, and involved inadequate separation between electrical power cables to the RCS pressurizer PORV and its associated block valve. The power supply to these valves were separated by less than 20 feet without the required fire barriers. This problem was only applicable to Unit 2. TVA's analysis of this discrepancy found that these interactions did not render these circuits inoperable. In addition, the existing automatic fire suppression and fire detection systems installed in the interaction areas and the roving fire watch provided for these areas would have resulted in a fire in these areas being identified and appropriate corrective actions taken to ensure safe plant shutdown.

The inspector reviewed the following corrective actions and verified that these items had been completed:

- A total of 39 drawings were revised to correct the cable interaction discrepancies.

- The Fire Hazard Analysis was revised for Mechanical Equipment Rooms A8 and A9 on 749' elevation of the auxiliary building.

- TVA informed the NRC by letter dated July 19, 1990 of the corrective actions required following completion of the Fire Hazards Analysis.

- The cable interaction problems were corrected by DCN M-04309-1. This DCN was issued to reroute the required cables. The inspector reviewed the work completion forms for this DCN which verified that the required work had been completed.

- Additional sprinkler heads were installed beneath cable trays in mechanical equipment Rooms A8 and A9 by DCNs M-06041-A and M-06043-A. The work completion forms for these DCNs were reviewed which verified that these additional sprinklers had been installed.

5.1.8 REVIEW OF UFSAR ASSOCIATED WITH FIRE PROTECTION AREA

UFSAR Section 9.5.1.4 states that the low pressure CO_2 system is tested in accordance with surveillance instructions which are based on the applicable NFPA code requirements. The CO_2 system for the cable spreading room has not been tested since 1982. This system is not listed as a required system by the TS but is a backup to the automatic sprinkler system installed in the cable spreading room; therefore, the

licensee does not consider that this system is required to be tested. As noted in paragraph 5.1.5, this item was identified by TVA during a 1995 audit. TVA's resolution was to remove this system from the cable spreading room and delete the reference to this system in the UFSAR. NRC's guidelines in NUREG-0800 Standard Review Plan, Section 9.5.1, requires a water suppression system for cable spreading rooms but does not require a backup CO_2 system. The proposed corrective actions were satisfactory.

TVA's fire protection commitments were primarily in letters and documents which were sent to the NRC at various times since 1977. Presently, TVA is preparing a detailed report which will include all of this data in one document. This document is scheduled to be sent to the NRC in August of 1996.

5.2 RADIOLOGICAL CONTROLS REVIEWS

During the Unit 1 forced outage period, the inspectors toured the Unit 1 containment several times and observed radiological controls implemented for the outage. The inspectors noted good ALARA sensitivity by both health physics technicians and other plant personnel. Examples included displays of a good questioning attitude and housekeeping sensitivity by the health physics technicians during containment inspection activities.

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

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

During this period, the inspector held discussions with licensee management and personnel regarding activities associated with Site Quality observations and independent third party observations regarding field observations by management. Significant weaknesses were identified in the Operations Performance Evaluation NA-SQ-95-009, dated June 23, 1995, in that Senior Operations management did not conduct plant tours on a regular basis to coach and reinforce expectations. In addition, some observations have been made (NA-SQ-95-018) regarding maintenance/modifications supervision not correcting performance problems when observing worker performance. Assessment NA-SQ-96-04 identified that maintenance/modification work practices and management monitoring have not been effective in ensuring screws, bolts, cover plates, etc., were restored to design condition following maintenance or modification.

The inspector held discussions with operations management to determine the formal and/or informal processes used to address the expectations regarding field observations. The inspector found that the operations department uses a formal process, outlined in Operations Directive Manual 2.1. This directive sets forth management expectations and guidelines regarding oversight of training and qualification activities. Observations of plant, MCR, and simulator work performance are required

at specified intervals for operations management, including the Operations Manager, Operations Superintendent, Unit Managers, SOS, ASOS, and others. The inspector reviewed several completed observation forms, and noted that approximately 20-35 observations had been completed each month since the inception of the program (approximately September 1995).

The inspector held discussions with AUOs regarding the presence of supervisory personnel in the field. The AUOs stated that, in general, an increased presence had been observed, and that there appeared to be greater accessibility to operations supervisory personnel.

The inspector also held discussions with Maintenance management regarding the processes used to provide coaching and expectations to field personnel. Maintenance management has recently implemented, via a departmental memo, the use of a peer evaluation card, used by general foreman and other maintenance and modifications supervisors. This action was taken in response to PER No. SQ952192PER, which identified through a common cause analysis, configuration issues caused by maintenance/modification personnel. This process has been in place for approximately 3 weeks, and approximately 200 evaluation cards have been completed to date. The inspector considered this number of evaluation cards to be a positive indication of increased emphasis on oversight and field observations by maintenance/modifications management. The inspector reviewed a sample of the completed cards, and noted that many substantive observations had been made. Maintenance management stated that this information will be used as part of the quarterly maintenance self-assessment.

The inspector held discussions with several maintenance and modifications craft personnel regarding the communication of expectations of management. Licensee personnel stated that increased emphasis had been observed by first-line supervisors regarding the conduct of maintenance.

The inspector concluded that the licensee was successful at providing increased supervisory oversight in the field in the operations and maintenance/modifications area. Based on the completed observations reviewed, substantive feedback has been provided to licensee personnel based on recent licensee efforts in the operations and maintenance/modifications area. Licensee management expressed the need for continued emphasis in this area to be fully effective.

Within the areas inspected, no violations were identified.

7.0 OTHER NRC PERSONNEL ON SITE

On March 25, 1996, an NRC/TVA management meeting, which was open to the public, was held at the Sequoyah Training Center. Representing NRC

management were Stewart D. Ebneter, Regional Administrator-Region II; Jon R. Johnson, Deputy Director-Division of Reactor Projects, Region II; Frederick J. Hebdon, Director-Project Directorate II-3, NRR; and Mark S. Lesser, Chief, Reactor Projects Branch 6, Region II. Prior to the meeting, the resident inspectors discussed recent plant performance and toured various parts of the plant with the above managers.

8.0 **UPDATED FINAL SAFETY ANALYSIS REVIEWS** (71707, 62726, 62703, 37751, 71750, 64704)

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

During this inspection period, the inspectors reviewed the applicable sections of the Updated Final Safety Analysis Report that related to the areas inspected. The following inconsistencies were noted between the wording of the Updated Final Safety Analysis Report and the plant practices, procedures and/or parameters observed by the inspectors.

- UFSAR Section 9.1.3.3.2 stated that under certain conditions the SFP water loss by vaporization would be about 55 gpm. The licensee recognized this error and recent licensee evaluation determined that the actual vaporization would be approximately 103 gpm. Corrected data will be included in the next revision of the UFSAR which will be submitted by January 1, 1997. Several additional SFP UFSAR changes will be made in the January 1997 revision, which will incorporate the analysis performed for the SFP rerack project which was completed in 1995.

- UFSAR Section 9.5.1.4 stated that the low pressure CO_2 system is tested in accordance with surveillance instructions which are based on the applicable NFPA code requirements. The CO_2 system for the cable spreading room has not been tested since 1982. This system is not listed as a required system by the TS but is a backup to the automatic sprinkler system installed in the cable spreading room; therefore, the licensee does not consider this system is required to be tested. This item was identified by TVA during a 1995 audit. TVA's resolution was to remove this system from the cable spreading room and delete the reference to this system in the UFSAR. NRC's guidelines in NUREG-0800 Standard Review Plan, Section 9.5.1, requires a water suppression system for cable spreading rooms but does not require a backup CO_2 system.

- UFSAR Section 6.8 described the licensee's pump and valve inservice testing program for the first 10-year inservice inspection period. However, the licensee commenced the second 10-year inservice inspection period in December 1995. The licensee intends to remove Section 6.8 from the UFSAR as discussed in

NUREG-1482, GUIDELINES FOR INSERVICE TESTING AT NUCLEAR POWER PLANTS. The UFSAR revision will be accomplished as part of DCN S-12020-A, which was initiated on December 12, 1995.

UFSAR required changes noted above will be made in the January 1997 revision. The inspectors determined the update schedule was consistent with the requirements of 10 CFR 50.71(e)(4).

9.0 (OPEN) EA 95-252, NOTICE OF VIOLATION (SEVERITY LEVEL II) AND IMPOSITION OF CIVIL PENALTY ($80,000) FOR ALLEGED DISCRIMINATION AT SEQUOYAH

On February 20, 1996, the NRC issued a Severity Level II violation with an $80,000 Civil Penalty for three instances where TVA failed to comply with the requirements of 10 CFR 50.7, Employee Protection, which prohibits discrimination against an employee for engaging in protected activities. The violation was associated with events in 1991 and a subsequent decision by the Secretary of Labor on October 23, 1995. The NRC adopted the Secretary of Labor's decision, and found that the adverse actions taken against a TVA employee were in retaliation for engaging in protected activities. By letter dated March 15, 1996, TVA requested that the NRC defer issuance of orders imposing a civil penalty because of planned appeals by TVA. By letter dated April 4, 1996, the NRC agreed to defer issuance of orders imposing the civil penalty pending the outcome of the appeals.

10.0 EXIT

The inspection scope and findings were summarized on April 1, 1996, by William E. Holland with those individuals identified by an asterisk in paragraph 1. Interim exits were conducted on March 1, 8, 14, 15, 22, and 29. 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
VIO	327, 328/96-02-01	OPEN	Failure to Establish or Implement Procedures for Component Cooling System Operation During Testing Activities (paragraph 2.2.3)
IFI	327, 328/96-02-02	OPEN	Review Corrective Actions of PER No. SQ960759PER Regarding CCS Surge Tank Overflow (paragraph 2.2.3)

IFI	327/96-02-03	OPEN	Followup On Licensee Evaluation, Cause Determination, and Corrective Actions for PER No. SQ960647PER Associated With Incorrect Assembly of the Unit 1, #2 RCP seal During Maintenance (paragraph 3.1)
IFI	327,328/96-01-01	CLOSED	Followup on OT2 Handswitch Failures (paragraph 3.6.1)
LER	327/95-10	CLOSED	Turbine and Reactor Trips Resulting From a Failure of the 'A' Phase Main Transformer Sudden Pressure Relay (paragraph 3.6.6)
URI	327,328/96-02-04	OPEN	Inadequate Safety Assessment for Rod Control System (paragraph 4.1.5)
VIO	327, 328/96-02-05	OPEN	Failure to Control Implementation of Plant Modifications as Required by SSP-9.3 (paragraph 4.6)
VIO	327,328/95-13-01	CLOSED	Inadequate Implementation of Corrective Actions for Arrow-Hart Starter Contactor (paragraph 4.7)
IFI	327,328/94-28-01	CLOSED	Acceptability of In-house Test Performed on 110 Vac Contactor (paragraph 4.7)
IFI	327,328/93-35-01	CLOSED	PVC Cable Extruding Plasticizer (paragraph 4.7)
IFI	327, 328/96-02-06	OPEN	Evaluation of Corrective Action Taken on TVA's Fire Protection Audit Findings (paragraphs 5.1.2 and 5.1.5)
VIO	327, 328/96-02-07	OPEN	Inadequate Storage and Maintenance of Fire Pumps and Fire Pump Components in Long Term Storage (paragraph 5.1.6)

EA	95-252	OPEN	Civil Penalty for Three Instances where TVA Failed to Comply with 10 CFR 50.7 (paragraph 9)

11.0 ACRONYMS

AFW	Auxiliary Feedwater
ALARA	As Low As Reasonably Achievable
ANSI	American National Standard Institute
AOP	Abnormal Operating Procedure
ASME	American Society of Mechanical Engineers
ASOS	Assistant Shift Operations Supervisor
AUO	Assistant Unit Operator
BOP	Balance of Plant
CCS	Component Cooling System
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CO_2	Carbon Dioxide
CRDM	Control Rod Drive Mechanism
CS	Containment Spray
CSST	Common Station Service Transformer
DCN	Design Change Notice
DG	Diesel Generator
DSSA	Division of Systems Safety and Analysis
EA	Escalated Action
EHC	Electro-Hydraulic Control
EQ	Environmental Qualification
ERCW	Essential Raw Cooling Water
°F	Degree Fahrenheit
FCV	Flow Control Valve
FIN	Fix It Now
FPI	Fire Protection Instruction
GL	Generic Letter
gpm	Gallons Per Minute
HO	Hold Order
IFI	Inspector Followup Item
IPE	Individual Plant Examination
IR	Inspection Report
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MCC	Motor Control Center
MCR	Main Control Room
MI	Maintenance Instruction
MOV	Motor Operated Valve
MRC	Management Review Committee
MW	Megawatts
NE	Nuclear Engineering
NFPA	National Fire Protection Association
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation

NUPIC	Nuclear Procurement Issues Council
NUREG	NRC Technical Report Designation
PER	Problem Evaluation Report
PM	Preventive Maintenance
PMT	Post Maintenance Testing
PORV	Pressure Operated Relief Valve
psi	Pounds Per Square Inch
psig	Pounds Per Square Inch Gauge
PVC	Polyvinyl Chloride
PZR	Pressurizer
QA	Quality Assurance
QC	Quality Control
QIT	Quality Improvement Team
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RCW	Raw Cooling Water
RFO	Refuelling Outage
RHR	Residual Heat Removal
RO	Reactor Operator
RTO	Return To Operation
RVLIS	Reactor Vessel Level Instrumentation System
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SI	Surveillance Instruction
SOS	Shift Operations Supervisor
SRO	Senior Reactor Operator
SSP	Site Standard Practice
SSPS	Solid-State Protection System
TDAFP	Turbine Driven Auxiliary Feedwater Pump
TS	Technical Specifications
TSIR	Technical Support Investigation Request
TVA	Tennessee Valley Authority
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
V	Volt
Vac	Volts Alternating Current
VIO	Violation
VLV	Valve
WO	Work Order
WOG	Westinghouse Owners Group
WR	Work Request
WRC	Welding Research Council