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

Report Nos.: 50-327/92-31 and 50-328/92-31

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: September 27 through October 31, 1992

Lead Inspector: Paul J Kellogg for 11/5/92
W. E. Holland, Senior Resident Inspector Date Signed

Inspectors: S. M. Shaeffer, Resident Inspector
S. E. Sparks, Resident Inspector

Approved by. Paul J Kellogg 11/5/92
Paul J. Kellogg, Chief, Section 4A Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant operations, plant maintenance, plant surveillance, evaluation of licensee self-assessment capability, licensee event report closeout, followup on previous inspection findings, and ESF system walkdown. During the performance of this inspection, the resident inspectors conducted several reviews of the licensee's backshift or weekend operations.

Results:

In the area of Operations, an example of good operator sensitivity to potential high risk evolutions was observed. The observation involved control room supervision providing conservative reviews of planned activities which identified that work contingencies needed to be developed prior to proceeding with the activity (paragraph 3.a.2).

In the area of Engineering, the licensee's technical support activities to identify a problem associated with increased ice buildup on ice condenser intermediate doors, and pursuit of short term corrective actions was considered pro-active (paragraph 5.a).

In the area of Safety Assessment, a unresolved item was identified with regard to determination of requirement of TS 4.6.5.1 during performance for "as found" ice condenser status (paragraph 6).

In the area of Security, a weakness was identified with regard to a lack of management involvement to effect timely corrective action for known lighting deficiencies; and, living with compensatory measures for the deficiencies prior to NRC involvement in the issue (paragraph 8.c).

In the area of Safety Assessment, a weakness was identified with regard to attention to detail in fully understanding and clarifying system operation for the Component Cooling System. During a walkdown of the system, a number of discrepancies were identified in the areas of labeling, annunciators, and compliance with the FSAR (paragraph 9).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*J. Wilson, Site Vice President
*R. Beecken, Plant Manager
*L. Bryant. Maintenance Manager
*M. Cutlip, Site Support Coordinator
*M. Cooper, Site Licensing Manager
*T. Flippo, Site Quality Assurance Manager
*J. Gates, Technical Support Manager
*O. Hayes, Special Projects Manager
*B. Jocker, Chemistry Manager
*C. Kent, Radiological Control Manager
*M. Lorek, Operations Superintendent
P. Lydon, Operations Manager
R. Rausch, Modifications Manager
J. Smith, Regulatory Licensing Manager
*R. Thompson, Compliance Licensing Manager
*P. Trudel, Nuclear Engineering Manager
*J. Ward, Engineering and Modifications Manager
N. Welch, Unit Manager

NRC Employees

B. Wilson, Chief, DRP Branch 4
P. Kellogg Chief, DRP Section 4A

* Attended exit interview.

Other licensee employees contacted included control room operators, shift technical advisors, shift supervisors and other plant personnel.

Acronyms and initialisms used in this report are listed in the last paragraph.

On October 20 and 21, 1992 the NRC Region II Section Chief, P. Kellogg, visited the Sequoyah Nuclear Plant. Mr. Kellogg met with the resident office staff, met with licensee management, and participated in meetings relating to inspection activities. Mr. Kellogg also toured the plant with the resident inspectors.

On November 26, 1992 regional and headquarters management visited the Sequoyah Nuclear Plant to participate in the presentation of the SALP evaluation for the period of June 2, 1991 through August 1, 1992. Nrc management included:

S. D. Ebneter, Regional Administrator, RII
G. C. Lainas, A/D Director for Region II Reactors, NRR
E. W. Merschoff, Director, Division of Reactor Projects, RII
B. A. Wilson, Chief, DRP. Branch 4
D. E. LaBarge, Sequoyah Project Manager, NRR

The SALP presentation was conducted in the licensee's training center on site. SALP results are described in NRC Inspection Report 327, 328/92-26.

2. Plant Status

Unit 1 began the inspection period at approximately full power. On October 26, the unit experienced an automatic reactor trip due to a turbine trip from a high-high steam generator level condition. The unit was stabilized and remained in Mode 3 through the end of the inspection period. This transient is further discussed in paragraph 3.f(3) of this report.

Unit 2 began the inspection period at approximately full power. On October 26, the unit experienced an automatic turbine runback to approximately 65 percent power due to a water intrusion problem in the control air system affecting the control valves for the Unit 2, #3 heater drain tank. After the runback, operators continued to reduce power to approximately 31 percent, until plant management concluded that the unit was in a stabilized condition. The unit remained at approximately 31 percent through the end of the inspection period. This transient is further discussed in paragraph 3.f(3) of this report.

3. Operational Safety Verification (71707)

a. Daily Inspections

The inspectors conducted daily inspections in the following areas: control room staffing, access, and operator behavior; operator adherence to approved procedures, TS, and LCOs; examination of panels containing instrumentation and other reactor protection system elements to determine that required channels are operable; and review of control room operator logs, operating orders, plant deviation reports, tagout logs, temporary modification logs, and tags on components to verify compliance with approved procedures. The inspectors also routinely accompanied plant management on plant tours and observed the effectiveness of management's influence on activities being performed by plant personnel.

(1) During a backshift inspection conducted on September 30, 1992, the inspectors identified a failed low SG #1 main steam pressure indication (1-PI-1-1C) in the Auxiliary Shutdown Control Room (ASCR). This remote shutdown monitoring instrumentation is required by Technical Specification 3.3.3.5 and is subject to a seven day LCO for repair prior to placing the unit in hot shutdown. The inspectors immediately identified the condition to the SOS. The licensee entered the TS LCO and initiated WR C131778 to troubleshoot the PI. The PI failure was determined to be an

intermittent electronic failure. Performance of the WR was successfully completed several days later and the instrument was returned to service. The inspectors considered the corrective actions complete.

The inspectors also reviewed the frequency of licensee inspections in the ASCR. The results indicated that the licensee fully implemented the TS required monthly surveillance for shutdown monitoring instrumentation. However, the inspectors questioned the licensee regarding the frequency of operational checks of TS required instrumentation for the ASCR. The inspectors considered that the monthly check may not reflect adequate identification opportunity in relation to the seven day shutdown LCO. The inspectors discussed this with Operations management. The licensee decided that a more frequent check of the ASCR would be prudent. At the end of the inspection period, the licensee was reviewing procedures for incorporation of the ASCR check during weekly operational rounds. The inspector had no further concerns and considered management's decision appropriate.

(2) On October 22, 1992 the inspectors attended a main control room pre-test briefing for SI-62, PRIMARY CONTAINMENT VACUUM RELIEF VALVE AUTO-OPEN, Rev. 14. The purpose of this SI is to verify operability of primary containment vacuum relief valves 30-571, 30-572, and 30-573. Failure to verify operability of one of these valves would result in entry into TS LCO action 3.6.6.1, which requires that the inoperable valve by restored to operable status within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

During the pre-test brief, control room supervision identified that some contingency plans had not been developed. Specifically, contingency work requests did not exist for a failure of the relief valves to meet acceptance criteria, a general failure of the relief valves, or a failure of motor operated valves FCV-30-46, FCV-30-47, and FCV-30-48. Control room supervision expressed these concerns to the appropriate personnel, and delayed SI-62 until such time that these contingencies could be developed. The inspectors consider this to be an example of good operator sensitivity to potential high risk evolutions.

b. Weekly Inspections

The inspectors conducted weekly inspections in the following areas: operability verification of selected ESF systems by valve alignment, breaker positions, condition of equipment or component, and operability of instrumentation and support items essential to system actuation or performance. Plant tours were conducted which included observation of general plant/equipment conditions, fire protection and preventative measures, control of activities in progress, radiation protection controls, missile hazards, and plant housekeeping conditions/cleanliness.

c. Biweekly Inspections

The inspectors conducted biweekly inspections in the following areas: verification review and walkdown of safety-related tagouts in effect; review of the sampling program (e.g., primary and secondary coolant samples, boric acid tank samples plant liquid and gaseous samples); observation of control room shift turnover; review of implementation and use of the plant corrective action program; verification of selected portions of containment isolation lineups; and verification that notices to workers are posted as required by 10 CFR 19.

d. Other Inspection Activities

Inspection areas included the turbine building, diesel generator building, ERCW pumphouse, protected area yard, control room, vital 6.9 KV shutdown board rooms, 480 V breaker and battery rooms, and auxiliary building areas including all accessible safety-related pump and heat exchanger rooms. RCS leak rates were reviewed to ensure that detected or suspected leakage from the system was recorded, investigated, and evaluated; and that appropriate actions were taken, if required. The inspectors routinely independently calculated RCS leak rates using the NRC RCS leak rate computer program specifically formatted for Sequoyah. RWPs were reviewed, and specific work activities were monitored to assure they were being accomplished per the RWPs. Selected radiation protection instruments were periodically checked, and equipment operability and calibration frequencies were verified.

e. Physical Security Program Inspections

In the course of the monthly activities, the inspectors included a review of the licensee's physical security program. The performance of various shifts of the security force was observed in the conduct of daily activities to include: protected and vital area access controls; searching of personnel and packages; escorting of visitors; badge issuance and retrieval; and patrols and compensatory posts. In addition, the inspectors observed protected area lighting, and protected and vital areas barrier integrity.

f. Licensee NRC Notifications

(1) On September 29, 1992 the licensee made a four hour non-emergency notification as required by 10 CFR 50.72 with regard to a notification made to TEMA concerning inadvertent

sounding of an emergency siren on owner controlled property. No actual emergency condition existed at the time the siren sounded.

(2) On October 24, 1992, the licensee made a four hour non-emergency notification to the NRC as required by 10 CFR 50.72 due to the notification of an off-site government agency. The notification to the National Response Center was made due to a lubricating oil leak from the facility into the U.S. waters bordering the site (Tennessee River). The oil leak into the Tennessee River was from the ERCW pumping station. The undetermined volume of oil resulted in an oil sheen on the river estimated to be approximately 50 square feet in area. The oil originated at an overflowing oil catch pan within the pumping station. The overflow was the result of water overspray by an ERCW traveling screen wash pump into the catch pan.

(3) On October 26, 1992 at 6:54 p.m., Unit 1 experienced a runback, and then a automatic reactor trip from approximately 100% power. The reactor trip was due to a turbine trip from a high-high steam generator level condition for the #3 steam generator. The high steam generator level condition was caused by the #3 steam generator regulating valve failing open due to an electrical problem with a valve control relay. The valve went open after operators selected manual control in order to respond to erratic valve operation after a moisture intrusion event which had occurred in the control air system. Approximately the same time that Unit 1 tripped, Unit 2 experienced a turbine runback from 100% power to approximately 65% power due to the control air moisture intrusion event affecting the level control valves for the Unit 2, #3 heater drain tank. A high level in the tank resulted in opening of the drain tank bypass valves and the subsequent runback. Operators continued to reduce power on Unit 2 to approximately 55% at which time it was determined that the control air water intrusion condition had been stabilized.

All safety systems performed as designed on Unit 1 with the unit being stabilized in mode 3. Auxiliary feedwater was being used to maintain steam generator level and decay heat was being removed by steaming to the main condenser. Unit 2 neither had nor required any safety system actuation.

The inspectors responded to the site after being notified of the event. Their evaluation of licensee actions associated with the water intrusion into the control air system was discussed in NRC Inspection Report 327, 328/92-34.

Within the areas inspected, no violations were identified.

4. Maintenance Inspections (62703 & 42700)

During the reporting period, the inspectors reviewed maintenance activities to assure compliance with the appropriate procedures and requirements. Inspection areas included the following:

On September 28, the inspectors became aware of activities involving questionable qualification of the K-A ERCW pump handswitch which was located in the main control room. A rebuild of the K-A pump had recently been completed; however, handswitch operability concerns were raised prior to the pump being returned to operable status. The inspectors discussed the handswitch concerns with System and Nuclear Engineering and were informed that the issue was the result of licensee followup on CAQR SQP900124 which was initiated March 5, 1990. The CAQR stated that category 1E switches on the main control boards of the W2 & 02 (Westinghouse) variety have been repaired without instructions from the vendor (or in a procedure) to ensure continued 1E classification. The original 1E classifications were performed by the licensee via testing due to the unavailability of vendor supplied switches. Vendor supplied 1E switches subsequently became available to the licensee in 1987. The concern regarding current qualification was discovered during licensee/vendor discussions in 1990 for switch spare part procurement. During these discussions, the vendor informed the licensee that qualification classification could not be maintained if the switches were not vendor repaired. The licensee had knowledge that they had preformed work on switches; however, the specific components were not readily identifiable. The licensee did however, consider all of the potentially affected handswitches operable and qualified based on the initial licensee qualifications and subsequent repairs performed with approved procedures. The CAQR developed actions to review WRs associated with the subject switches to ascertain whether the work may have affected switch qualification. It should be noted that the initial qualification of the handswitches were for seismic considerations.

The review to determine the affected switches was not completed until October of 1992. Technical Support and NE personnel indicated that resolution of the issue was delayed due to the priority of the issue in the engineering backlog. The results of the review indicated the following 1E handswitches were affected:

0-HS-067-0436A, ERCW pump K-A

0-HS-067-0152A, Component Cooling Htx C Discharge to Header B - ERCW

2-HS-063-0133A, SIS - Train A & B Actuation

1-HS-030-0451C, EDG 1A-A Exhaust Fan 2-A

1-HS-003-0128A, AFW Pump 1B-B

1-HS-001-0022A, SG 3 Main Steam Header Isolation Switch

2-HS-063-0010A, SIS Pump 2A-A

The inspectors discussed the operability and qualification of the above handswitches with NE personnel and also reviewed an engineering evaluation prepared to address the concerns of CAQR SQP900124. The evaluation included factors such as reviews of past handswitch maintenance activities, performance of appropriate PMT following handswitch work, and initial qualification tests. The licensee in all instances considered the handswitches operable and qualified. However, plans to replace the switches which may have not been repaired by the vendor in order to maintain qualification consistency were initiated. Corrective actions included replacement of switches currently available for changeout and scheduling replacement of the remaining handswitches during each units' respective cycle 6 refueling outages. The inspectors had no further concerns; however, considered the followup on the CAQR corrective actions to be untimely.

Within the areas inspected, no violations were identified.

5. Surveillance Inspections (61726 & 42700)

During the reporting period, the inspectors reviewed various surveillance activities to assure compliance with the appropriate procedures and requirements. The inspection included a review of the following procedures and observation of surveillances:

a. During the week of October 5, 1992 the inspectors reviewed the licensee's activities associated with SI-103.1, ICE CONDENSER INTERMEDIATE DOOR VISUAL INSPECTION AND TEST. The licensee performs this surveillance to satisfy TS 4.6.5.3.2 The surveillance consists of a visual inspection of all intermediate doors (192 total) on a seven day frequency. If ice/frost is discovered, a test is performed to determine freedom of door movement when lifted with the applicable force as stated in TS 4.6.5.3.2.b (as-found test). If one or more doors fail to pass the test, the licensee enters the TS LCO ACTION statement 3.6.5.3.b which requires, in part, that POWER OPERATION may continue for specified time periods (14 days) and the doors must be restored to OPERABLE status within these periods. The ice/frost is then removed and the lifting test re-performed (as-left test). If satisfactory test results are achieved, the TS LCO ACTION statement is exited.

   On August 9, 1992 the licensee generated SQPER920273 in response to the failure of 9 of 192 Unit 1 ice condenser intermediate doors. Testing frequency was increased from once per week to twice per week. A summary of Unit 1 testing results below indicated a continuing problem:

8/17 - All doors passed	8/20 - All doors passed
8/24 - 16 doors failed	8/27 - 22 doors failed

8/31 - No surv. performed	9/3 - All doors passed
9/7 - All doors passed	9/10 - 5 doors failed
9/14 - All doors passed	9/17 - All doors passed
9/21 - 9 doors failed	9/24 - 1 door failed
9/28 - 9 doors failed	10/1 - 3 doors failed
10/5 - 13 doors failed	10/8 - 6 doors failed
10/10 - 2 doors failed	10/12 - 5 doors failed
10/15 - 10 doors failed	10/17 - All doors passed
10/19 - 8 door failed	10/22 - One door failed
10/23 - All doors passed	10/24 - All doors passed
10/25 - All doors passed	10/29 - All doors passed
10/31 - All doors passed	

The licensee entered the TS LCO action statement for the above intermediate doors, and the ice was then removed. As-left testing was performed to verify TS compliance. On at least two separate occasions, the intermediate doors failed as-left testing. The licensee appropriately did not exit the TS action statement until corrective actions were performed and the doors passed as-left testing.

The licensee has performed work requests to lubricate all ice condenser intermediate doors. In addition, consideration has been given to different lifting scales, due to poor repeatability of lifting force during the performance of SI-108.1. The licensee informed the inspectors that the SI-108.1 surveillance frequency would be increased from twice per week to three times per week. Over the inspection period, the licensee has been more aggressive in trying to locate the source of the problem of ice accumulation, as indicated by increased senior management attention.

In addition to the above door failures, a review of past surveillances indicated that many doors pass the surveillance (as found and as left) with a small margin. Discussions with licensee engineers indicated that the TS lifting force acceptance criteria is approximately five to ten pounds force more conservative than the Westinghouse recommended value. In addition, the licensee's TS values are three to five pounds force less than other facilities with identical containment ice condenser systems. For these reasons, the licensee is considering a TS change request to reduce these conservatism but still maintain adequate design margins.

The inspectors held discussions with system engineers, who indicated the potential cause to be associated with a CRDM cooler leak or a lower containment cooler leak, which would result in increased humidity levels. The leakage was conservatively estimated by the licensee to be 0.025 gpm. This small leakage rate would be difficult to locate during containment entry. The inspectors noted that with such a small leakage rate, the likelihood of similar problems in the future could be high. The system engineer indicated that no similar problems existed to his knowledge during the summer of 1991. The system engineer also indicated that an anticipated reduction in river water temperature due to the approach of the autumnal season would decrease humidity levels inside containment due to localized condensation on the lower containment cooler coils.

The licensee's short term plans are to perform SI-108.1 daily, and perform a daily containment purge to decrease humidity levels. The licensee anticipates a reduction in river water temperature, and thus a decreased ERCW temperature, to almost completely mitigate the increased humidity levels due to localized condensation on the lower containment cooler coils. Long term corrective actions include an evaluation to determine the feasibility of using a chilled water system (instead of ERCW) for the lower containment cooler. In addition, as stated above, a TS change request is being considered by the licensee.

Subsequent to the Unit 1 reactor trip on October 26, the licensee entered Unit 1 containment and identified a small pinhole leak in a lower containment cooler coil, which was repaired. At the end of this inspection period, the licensee did not know if this leak was the only contributor to the elevated Unit 1 containment elevated humidity levels.

The inspectors concluded the licensee's activities to identify the above problem, and pursuit of short term corrective actions, have been pro-active. The inspectors will continue to monitor the licensee's activities during future inspections.

b. On October 6, 1992 the inspectors witnessed portions of 2-SI-SXP-003-004.B, MOTOR DRIVEN AUXILIARY FEEDWATER PUMP 2B-B QUARTERLY OPERABILITY TEST, Rev. 0. The procedure utilizes an ultrasonic flow meter, located on the mini-flow line. The inspector verified that the placement of the flow meter is specifically identified. In addition, the inspectors verified through discussions with the test coordinator that the transducers used for the ultrasonic flow meter were calibrated for 1.5 inch, schedule 160 carbon steel pipe. The inspectors observed that the discharge pressure indicator was oscillating rapidly from approximately 1450 psi to 1670 psi during the test. The inspector verified that the discharge pressure was documented to be 1560 psi. However, the oscillations in pressure made the determination of the discharge pressure difficult. Discussions with the test coordinator indicated that pressure damping devices have been considered for use with Section XI pump testing. Damping of pressure oscillations would increase repeatability of measurements, and would be an improvement to the licensee's Section XI pump testing program. The inspectors also verified that the pump differential pressure and flow rate were located on the vendor's pump head curve.

c. The inspectors reviewed the licensee's activities in response to 2-SI-OPS-082-007.B, ELECTRICAL POWER DISTRIBUTION, DIESEL GENERATOR 2B-B, Rev. 2. The SI was performed on October 7, 1992. As the control room operators began slowly increasing load on the EDG, several operating parameters began to oscillate, including frequency, VARs, and current. The control room operators shutdown the EDG and troubleshooting of the problem began. It appeared that the oscillations were due to a loose contact in the speed controller potentiometer. The EDG was repaired, testing completed, and was returned to service at 3:46 a.m. on October 8, 1992. The licensee classified the EDG test as a valid test and failure, based on the guidance contained in Regulatory Guide 1.108, Periodic Testing of Diesel Generator Units Used As Onsite Electric Power Systems at Nuclear Power Plants, Rev. 1. The inspectors agreed with this classification, based on the fact that the EDG test was terminated intentionally before completion because of an alarmed abnormal condition that could have resulted in diesel generator damage or failure.

On October 9, the inspectors inquired whether the licensee had initiated work requests for the other EDGs to determine if a similar problem exists. Discussion with the system engineer indicated that no work requests had been written yet, but considered it prudent to do so. The work requests were written, and will be performed during each EDGs upcoming monthly test. The work requests had not been completed prior to the end of this inspection period.

Within the areas inspected, no violations were identified.

6. Evaluation of Licensee Self-Assessment Capability (40500)

During this inspection period, selected reviews were conducted of the licensee's ongoing self-assessment programs in order to evaluate the effectiveness of these programs. The inspectors specifically focused on several of the licensee's incident investigations during the inspection period.

On October 13, 1992 the inspectors meet with Quality Assurance site management to review their recent audit results and ongoing assessments of Sequoyah Nuclear Plant. During the discussions, the residents requested that additional information be provided with regard to QA identification, during a recent maintenance audit, of findings associated with review of surveillance procedures which were conducted during the Unit 1 Cycle 5 refueling outage. The findings were addressed at technical specification requirements for the ice condenser and how these requirements are considered with regard to the as found condition of the ice condenser.

On October 20, 1992 the inspectors again met with QA, licensing, and engineering personnel to discuss the QA findings associated with ice condenser surveillance requirements. The two findings specifically discussed involved (1) a finding that no upper limit was identified for boron concentration in ice for the ice condenser. This concern was based on review of surveillance instruction data which indicated sampling results as high as 2978 ppm; and, (2) a finding that identified weights of as found ice baskets which were below minimum design weights. This concern was also identified during surveillance instruction review for ice refurbishment activities accomplished during the Unit 1 Cycle 5 outage.

The first finding (SQFIR920075208) was discussed and the inspectors were informed that the finding was not a valid issue due to the chemical makeup of the boron ingredient for the ice manufacturing process (Sodium tetra borate). This ingredient was determined to be acceptable at boron concentrations up to 8000 ppm, therefore levels identified by the finding, which were measured up to 2978 ppm were satisfactory. The FIR documentation contained a design evaluation of the condition with justification for acceptance.

The second finding (SQFIR920068208) was discussed and the inspectors were informed that although the surveillance instruction (SI-106.2, ICE CONDENSER-ICE BED-UNIT 1) did not identify that specific as found ice basket weights were outside of the design basis (993 pounds), all technical specification requirements were satisfied prior to Unit 1 restart. The specific part of SI-106.2 that was in question was the part that accomplished TS SURVEILLANCE REQUIREMENTS 4.6.5.1 which states:

"The ice condenser shall be determined OPERABLE:

d. At least once per 18 months by:

> Weighing a representative sample of at least 144 ice baskets and verifying that each basket contains at least 1155 lbs of ice. The representative sample shall include 6 baskets from each of the 24 ice condenser bays and shall be constituted of one basket each from Radial Rows 1, 2, 4, 6, 8 and 9 (or from the same row of an adjacent bay if a basket from a designated row cannot be obtained for weighing) within each bay. If any basket is found to contain less than 1155 pounds of ice, a representative sample of 20 additional baskets from the same bay shall be weighed. The minimum average weigh of ice from the 20 additional baskets and the discrepant basket shall not be less than 1155 pounds/basket at a 95% level of confidence.
>
> The ice condenser shall also be subdivided into 3 groups of baskets, as follows: Group 1 - bays 1 through 8, Group 2 - bays 9 through 16, Group 3 - bays 17 through 24. The minimum average ice weight of the sample baskets from the Radial Rows 1, 2, 4, 6, 8 and 9 in each group shall not be less than 1155 pounds/basket at a 95% level of confidence.

> The minimum total ice condenser ice weight at a 95% level of confidence shall be calculated using all ice basket weights determined during this weighing program and shall not be less than 2,245,320 pounds."

The FIR identified a condition where the licensee did not complete all stated requirements of the TS surveillance requirements during the "as found" performance steps in SI-106.2. Specifically, the licensee did not weigh an additional 20 baskets after some baskets were found to contain less than 1155 pounds of ice. Also, the minimum weight of the Group 1, Row 1 baskets were determined to be less than the design weight of 993 pounds (TS requires the weight to be 1155 pounds or greater).

The inspectors questioned the licensee with regard to whether they must follow the TS during the "as found" determination of the ice condenser condition. The licensee's response was that the TS requirements only applied to the "as left" condition. The inspectors requested, and were provided a copy of the Safety Evaluation Report for Amendment No. 131 to the Unit 1 TS. The amendment revised applicable portions of TS SR 4.6.5.1 to include reducing the required basket weights from 1200 pounds to 1155 pounds. The SER justification for the revision, in part, stated that "operability of the ice beds in the ice condenser requires that the ice inventory be distributed evenly throughout the ice condenser bays in containment...". The inspectors questioned the licensee as to how they determined that the ice was evenly distributed throughout the operating cycle. This issue was being reviewed by both the licensee and the NRC when the inspection period ended. This item is identified as unresolved, URI 327, 328/92-31-01, Determination of requirement of TS 4.6.5.1 during performance for "as found" ice condenser status.

Within the areas inspected, one unresolved item was identified.

7. Licensee Event Report Review (92700)

The inspectors reviewed the LER listed below to ascertain whether NRC reporting requirements were being met and to evaluate initial adequacy of the corrective actions. The inspector's review also included followup on implementation of corrective action and/or review of licensee documentation that all required corrective action(s) were either complete or identified in the licensee's program for tracking of outstanding actions.

a. (Closed) LER 327/92-14, Safety-Injection Pump Inoperable Due to the Associated Circuit Breaker Being Nonfunctional. The event involved an immediate trip of the Unit 1 1B-B safety injection pump during performance of a quarterly surveillance pump run. The licensee immediately determined that the manual trip button for the associated circuit breaker was stuck in the trip position. After the button was repositioned, the surveillance was successfully performed. The cause of the stuck trip button could not be determined; however, the licensee considered the cause to have been a combination of failure of the breaker trip button to function and a lack of personnel attentiveness. Violation 327/92-29-01 was issued for failure to maintain the B train safety injection pump operable from July 31 to August 10, 1992. The final corrective actions taken for the event will be evaluated in the licensee's response to the violation.

Within the areas inspected, no violations were identified.

8. Action on Previous Inspection Findings (92701, 92702)

a. (Closed) URI 327, 328/90-26-03, Undocumented Design Change to Charging Pump Alignment. The issue involved licensee identification of welds which were not installed per requirements for alignment lugs on centrifugal charging pumps. Additional reviews of this issue, including weld installation processes and the change to the 2A pump alignment method, determined that the licensee has in place administrative controls for configuration changes resulting in modification to safety-related components. The inspectors reviewed the controls specified in SSP-6.24, MAINTENANCE MANAGEMENT SYSTEM CONFIGURATION CONTROL LOG, Revision 1. This procedure requires specific control of configuration changes, including weld modifications, to assure that equipment configuration was not changed without appropriate engineering authorization. The inspectors discussed the process with maintenance planning and management personnel and considered that these controls were adequate.

b. (Closed) VIO 327, 328/91-26-01, Failure to Take Effective and Timely Corrective Action for Previously Identified Event Involving Loss of RWST Level Indication Due to Flooding of RWST Basin. The issue involved flooding of the Unit 2 RWST Basin during a period of heavy rain resulting in loss of the subject instrumentation. The event was similar to an event that occurred which caused a loss of the Unit 1 RWST level instrumentation in 1989. The licensee responded to the violation in a letter dated January 22, 1992. Corrective actions included additional formal requirements for operators to periodically check the basins for water. Also, a design change has been implemented to allow for draining of the RWST basins which deletes the requirement for operators to drain the basins. The inspectors verified that licensee commitments were implemented and also verified that the basin drains were installed and operable.

c. (Open) URI 327, 328/92-30-01, Determination of Licensee Compliance with Security Plan with Respect to Protected Area Lighting Deficiencies. The issue, which was discussed in inspection report 327, 328/92-30, involved a condition where the inspectors observed that several of the plants protected area lights were not working properly. The condition was discussed with licensee security management and the inspectors concluded that less than adequate attention had been given to correction of known lighting deficiencies during the past several months. The inspectors noted that identification of lighting deficiencies were being documented; however, the method of identification did not provide for appropriate priority to correct the deficiencies in a timely manner. Subsequent to the inspectors identification of this issue, management action was initiated to require work requests to be submitted identifying security lighting deficiencies in lieu of a service request.

Subsequent to identification of the issue, the licensee has repaired most of the lighting deficiencies. An additional inspection of the lighting in the protected area was conducted by a region based security inspector on October 2?, 1992. The inspector concluded that adequate corrective actions had been accomplished with regard to lighting deficiencies that were discussed in report 92-30. The security inspector reviewed the licensee's security plan with respect to this unresolved issue and addressed closeout of the item in inspection report 327, 328/92-32.

The inspectors reviewed the licensee's corrective actions with regard to assuring that security lighting deficiencies receive appropriate priority consideration and consider that the actions taken were adequate. However, the inspectors consider that actions taken by security supervision and management to correct known lighting deficiencies in a timely manner was ineffective. In addition, living with compensatory measures for the deficiencies prior to NRC involvement in the issue was also an extension of the weakness.

Within the areas inspected, no violations were identified.

9. ESF System Walkdown (71710)

During the period the inspectors conducted a walkdown of the Component Cooling System. This system was chosen for walkdown due, in part, to identification by the Sequoyah Nuclear Plant IPE that a high percent of core damage frequency scenarios involves RCP seal failures; and, the highest contributor to RCP seal failure is a total loss of the CCS, or loss of Train A CCS without timely operator action to trip the RCPs.

The walkdown and review included verification of proper system configuration based on current plant operating conditions, review of selected procedures and control room indication and mimic alignments to maintain configuration, and review of FSAR sections discussing the CCS.

Specific reviews included portions of the following:

- FSAR, Section 9.2

- Annunciator response procedures

- Abnormal Operating Instruction - 15, LOSS OF COMPONENT COOLING WATER, Rev. 16

- Safety Assessment DCN M06225A, CCS HX "A" REPLACEMENT

A review of the licensee's IPE, section 6.3.1, recommended enhancements to procedure AOI-15, LOSS OF COMPONENT COOLING WATER, to facilitate the stopping of the RCPs on loss of CCS train A to minimize the potential for RCP seal damage due to pump bearing failure. The inspectors reviewed AOI-15, and held discussion with the Operations Superintendent about the revisions to procedure AOI-15. In general, the planned revisions would include improved guidance on when to trip the RCPs upon loss of CCS train A pumps. At the end of the inspection period, the procedure revisions were in the approval process.

The inspectors performed an independent system walkdown determined that system components were correctly aligned for both units. Additional walkdowns were conducted with the System Engineer. Discrepancies; however, were identified by the inspectors during system walkdowns and procedure reviews. The preliminary concerns were discussed and reviewed with the System Engineer and are listed, by category, as follows:

a. System Labeling (MCR)

   1. 1-LI-70-99A, CCS surge tank A outlet level
      1-LI-70-63A, CCS surge tank A inlet level
      2-LI-70-99A, CCS surge tank A outlet level
      2-LI-70-63A, CCS surge tank A inlet level

      Labeling for the CCS surge tank level instrumentation was misleading due to the outlet and inlet designations. In addition, the Unit 2 instrumentation should reflect tank "B" instead of "A". Tagging request T302743 was subsequently written to address this error.

   2. 2-PI-70-17A, CCS HX B Inlet Pressure

      The label should read "CCS HX 2A1/2A2"

   3. Above 1-HS-70-66A, Surge Tank Vent Valve, the mimic label contains misleading information. Also, mimic reflects "Surge Tank 1", while applicable drawings reference "Surge Tank A".

   4. Above 2-HS-70-66A, Surge Tank Vent Valve, the mimic label contains misleading information. Also, mimic reflects "Surge Tank 2", while applicable drawings reference "Surge Tank B".

5. Missing label for 1B-B RHR HX. Tagging request T333099 previously submitted for this error.

6. Labels for handswitches 2-HS-70-63A and 2-HS-70-66A, indicate "CCS Surge Tank A...", while applicable drawings reference tank "B".

b. System Labeling ASCR

Similar discrepancies to the MCR were noted on associated CCS instrumentation in the ASCR.

c. FSAR discrepancies

1. No CS pump header pressure indication in the MCR. This discrepancy was previously identified by the licensee. Current plans are to install the instrumentation in late 1993. This discrepancy directly related to the licensee's ability to provide the required indication identified in number 2 below. Corrective actions for this problem were identified in PCN 723.

2. No CS pump header pressure in the ASCR. This discrepancy was identified by the inspectors. The changes proposed in PCN 723 did not address this concern. The licensee initiated PER SQPER920330 to document the discrepancy.

3. No CCS discharge header low pressure alarm in the ASCR. This discrepancy was identified by the inspectors; however, the licensee considered the FSAR ambiguous in identifying this requirement. The licensee determined that this indication was not intended to be in the ASCR based on reviews of the FSAR drawings. The licensee agreed to review and clarify the ambiguous statements and/or correct the deficiency as appropriate. PER SQPER920330 also documented this discrepancy.

4. No plate heat exchanger outlet flow indications in the MCR. The inspectors determined that Safety Assessment DCN-MO6225A previously identified this as a requirement to be deleted in the next FSAR update. The inspectors reviewed DCN-MO6225A with regard to this change and could not identify where it was addressed on the safety evaluation. The inspectors discussed this with the Site Licensing Organization. The inspectors were informed that the proposed change had not yet been reviewed for final Licensing approval; however, based on the inspectors questions would be given an initial review. Based on the subsequent review, the proposed change was returned to engineering for reevaluation. The

inspectors considered the initial engineering review weak in this area.

In addition to the above discrepancies, the inspectors identified through discussions with operations personnel, that automatic surge tank make-up, which is required by the FSAR, may have not always been available. Past operational practices may have included placing the automatic make-up valve(s) (1, 2-70-63, one per tank) in the closed position rather than the automatic position due to operational considerations. This closed preference would allow for better CCS chemistry control and also provide a means of identifying and quantifying system leakage. During the inspectors walkdown of the MCR CCS configuration, the valves were configured in the automatic make-up position. The inspectors discussed the past practice of maintaining the automatic make-up valves closed with operations management. Although automatic makeup was identified as the proper method in the FSAR, it was concluded that there may be operational benefits when operating with the valves in the closed position (not in automatic). Operations management informed the inspectors that the valves will currently remain in automatic operation; however, an evaluation will be made regarding potential operational benefits by maintaining the valves closed. Any configuration changes would be subsequently addressed in the FSAR and supported by an engineering evaluation. It was also identified that the preferred position of the make-up valves was not detailed in a procedure. At the end of the inspection period, the licensee was reviewing the SOI for CCS to incorporate the handswitch position for operator guidance. The inspector had no additional concerns regarding the current operating configuration of the handswitch; however, recognized a lack of clear guidance to operators concerning past operation of the CCS surge tank make-up valves.

d. Annunciation Discrepancies

1. Annunciators have surge tanks labeled as Unit 1 or Unit 2. Drawings indicate tank identification as Tank A and Tank B.

2. The Unit 1 Abnormal Surge Tank Level Annunciator has a red "attention" border around the annunciator window, while the Unit 2 is bordered with white.

3. Annunciator response procedure for the Unit 1 and 2 Abnormal Surge Tank Level Annunciator listed alarm setpoint information in inches of water level. However, the level instrumentation in the control room indicated level in percent tank level and gallons. Operators were not familiar with the conversion factors.

At the end of the inspection period, the inspectors determined that operators were familiar with the CCS instrumentation, alarms, and system operation; however, the labeling, FSAR, and annunciator discrepancies could have contributed to operational errors if left uncorrected. The inspectors concluded that identified discrepancies indicated a weakness with regard to attention to detail in fully understanding and clarifying system operation.

Within the areas inspected, no violations were identified.

10. Exit Interview

The inspection scope and results were summarized on November 3, 1992 with those individuals identified by an asterisk in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. Proprietary material was not reviewed during the inspection period. Dissenting comments were not received from the licensee.

URI 327, 328/92-31-01	Determination of requirement of TS 4.6.5.1 during performance for "as found" ice condenser status.

Strengths and weaknesses summarized in the results paragraph were discussed in detail.

Licensee management was informed of the items closed in paragraphs 7 and 8.

11. List of Acronyms and Initialisms

AFW - Auxiliary Feedwater
AOI - Abnormal Operating Instruction
ASCR - Auxiliary Shutdown Control Room
CAQR - Condition Adverse to Quality Report
CCS - Component Cooling System
CFR - Code of Federal Regulations
CR - Control Room
DCN - Design Change Notice
DRP - Division of Reactor Projects
EDG - Emergency Diesel Generator
ERCW - Essential Raw Cooling Water
ESF - Engineered Safety Feature
FIR - Finding Identification Report
FSAR - Final Safety Analysis Report
GPM - Gallons per Minute
HX - Heat Exchanger
IPE - Individual Plant Examination
KV - Kilovolt
LCO - Limiting Condition for Operation

LER	-	Licensee Event Report
LI	-	Level Indication
MCR	-	Main Control Room
NE	-	Nuclear Engineering
NRC	-	Nuclear Regulatory Commission
NRR	-	Office of Nuclear Reactor Regulation
PCN	-	Project Control Number
PER	-	Problem Evaluation Report
PI	-	Periodic Instruction
PMT	-	Post-maintenance Test
QA	-	Quality Assurance
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RPM	-	Revolutions Per Minute
RWST	-	Refueling Water Storage Tank
RWP	-	Radiation Work Permit
SALP	-	Systematic Assessment of Licensee Performance
SER	-	Safety Evaluation Report
SG	-	Steam Generator
SI	-	Surveillance Instruction
SIS	-	Safety Injection System
SOI	-	System Operating Instruction
SOS	-	Shift Operating Supervisor
SR	-	Surveillance Requirement
SSP	-	Site Standard Practice
TEMA	-	Tennessee Emergency Management Agency
TI	-	Test Instruction
TS	-	Technical Specifications
TVA	-	Tennessee Valley Authority
URI	-	Unresolved Item
VIO	-	Violation
WR	-	Work Request