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

Report Nos.: 50-327/92-03 and 50-328/92-03

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 2 through 29, 1992

Lead Inspector: Paul J Kellogg for 3/10/92
W. E. Holland, Senior Resident Inspector Date Signed

Inspectors: S. M. Shaeffer, Resident Inspector
R. D. McWhorter, Resident Inspector
R. H. Bernhard, Project Engineer

Approved by: Paul J Kellogg 3/10/92
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, and followup on previous inspection findings. During the performance of this inspection, the resident inspectors conducted several reviews of the licensee's backshift or weekend operations.

Results:

In the Operations functional area, a violation was identified for failure to follow the requirements of 1-SI-OPS-000-002.0, SHIFT LOG in that operators recorded unacceptable flow information for several days prior to identification of a problem (paragraph 3.a.(1)).

In the Engineering/Technical Support functional area, a non-cited violation was identified for failure to follow the requirements of SSP-2.3 in that TI-28 did not have controlling requirements to prevent processing of new acceptance criteria for a TS surveillance parameter which was incorporated as an attachment (paragraph 3.a.(1)). Also, a weakness was identified with regard to the licensee's implementation of SSP-8.1 for resolution of a test deficiency without implementation of a procedure change (paragraph 3.a.(1)).

In the Operations functional area, a violation was identified for failure to follow the procedural requirements of AI-30 resulting in operators attempting to close reactor trip breakers while a valid trip signal was present (paragraph 3.a.(2)). An additional example was identified for failur o follow the procedural requirements of AI-30 after receiving unexpected annunciation during turbine trip testing. After identification of the source of the annunciation, operators failed to log the basis for continuing the procedure and failed to initiate revisions to address the problems prior to the next performance (paragraph 3.a.(3)).

In the Safety Assessment/Quality Verification functional area, a weakness was identified with regard to licensee implementation of the problem evaluation report part of the corrective action program. The weakness involved unclear guidance to personnel as to when to initiate problem evaluation reports (paragraph 3.b.(2)).

In the Maintenance/Surveillance functional area, a non-cited violation was identified for failure to conduct a preoperational checkout of the auxiliary building crane prior to operation on February 28, 1992 as required by SSP 6.6. (paragraph 3.b.(4)).

In the Operations functional area, a weakness was identified with regard to a lack of trending of important parameters for immediate operator use during operation with recognized degraded components (paragraph 3.d).

In the Operations function area, a violation was identified for failure to follow the procedural requirements of SSP-12.53 in that an evaluation pursuant to 10 CFR 50.59 was not performed in a timely manner for the removal of a safety-related annunciator from service (paragraph 5.a).

In the Maintenance/Surveillance functional area, a non-cited violation was identified for failure to follow the requirements of SSP-8.1 in that test performers failed to adhere to test instructions and subsequently caused an inadvertent actuation of fire protection equipment (paragraph 5.b). Also, an additional example of violation 327, 328/91-31-01 was identified. The example involved a failure to follow the requirements of AI-37 in that second party verification was not performed as required during performance of the fire protection surveillance test (paragraph 5.b).

In the Safety Assessment/Quality Verification functional area, a continuing strength was identified with regard to the incident investigation review process and the manner in which root causes for events are thoroughly discussed and understood prior to adjournment of Plant Evaluation Review Panel meetings (paragraph 6.d).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*J. Wilson, Site Vice President
*R. Beecken, Plant Manager
*L. Bryant, Maintenance Manager
*M. Cooper, Site Licensing Manager
*T. Flippo, Quality Assurance Manager
*J. Gates, Technical Support Manager
*C. Kent, Radiological Control Manager
*M. Lorek, Operations Superintendent
*P. Lydon, Operations Manager
R. Rausch, Modification Manager
*R. Rogers, Technical Support Program Manager
J. Smith, Regulatory Licensing Manager
*R. Thompson, Compliance Licensing Manager
*P. Trudel, Nuclear Engineering Manager
*C. Whittenmore, Licensing Engineer

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 February 7, 1992 the resident inspectors met with the new Operations Manager, P. Lydon for an introductory discussion. Mr. Lydon, who had been assigned to his new position since February 2, provided some background information on his experience. The residents provided some background information on their perspective of Sequoyah plant performance and both parties agreed to maintain an ongoing professional dialogue with regard to plant issues.

During the week of February 25 through 28, 1992 the NRC Region II project engineer for Sequoyah, R. Bernhard, visited the plant for badging, meeting the licensing staff, and general plant orientation. Mr. Bernhard toured the plant and attended several POD, PORC, and PERP meetings.

2. Plant Status

Unit 1 operated at approximately full power until February 13, when power was reduced to approximately 70% to repair one of the high pressure heater drain tank level control valves. On February 14, power was further reduced to approximately 30% after identification of condenser circulating water leakage into the main condenser. Several tubes in the main condenser required plugging due to leakage. After repairs were completed, the unit returned to full power operation on February 22 and operated at approximately full power until February 28 when power was reduced to 84% for repairs to a low pressure heater drain tank level control valve. The unit returned to full power operation on February 29, and ended the inspection period at full power.

Unit 2 began the inspection period in coastdown at approximately 95 percent power. On February 10, the unit experienced an automatic reactor trip from approximately 90% power. The trip is further discussed in paragraph 3.f.(2). The unit returned to power operation on February 12 and operated at power until February 16, when a secondary induced runback occurred reducing power from approximately 85% to 78% power. The unit returned to approximately 87% power on February , and operated in a coastdown mode for the remainder of the period. At the end of the period, the unit was operating at approximately 80 percent power in coastdown for the upcoming cycle 5 outage.

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) On February 9, 1992 the inspectors responded to the plant to followup on a licensee call made to the NRC where a condition was identified which may have placed Unit 1 outside of its design basis. This event is further discussed in paragraph 3.f.(1). The inspectors monitored licensee activities which included involvement of technical support and maintenance personnel in connecting of special equipment to the EAGLE racks to determine RCS flow conditions in order to resolve a discrepancy identified during performance of surveillance instruction 1-SI-OPS-000-002.0, SHIFT LOG, Revision 4. The inspectors also determined that the operators were handling the discrepancy in accordance with the requirements of Site Standard

Practice SSP-8.1, CONDUCT OF TESTING, Revision 2. This process included identification of a DN in the applicable test procedure (1-SI-OPS-000-002.0), documentation of the discrepancy on a problem evaluation report (PER SQ92-1501) and entry into the appropriate TS ACTION statement. After verification of adequate flow from the EAGLE racks, the licensee exited the TS ACTION statement.

During the inspectors review of the event, several problems were identified. The problems were:

- Review of 1-SI-OPS-000-002.0, indicated that operators had been recording flow information for several days which was lower than the acceptance criteria specified in technical instruction TI-28, CURVE BOOK, UNITS 1 AND 2, Revision 1, Attachment 5 which had been updated on January 18, 1992. 1-SI-OPS-000-002.0, page 20 required operators to determine RCS flow by recording flow instrument indication in the main control room and comparing the data to the requirements of Figure A.27 of TI-28, attachment 5. Operators, on several occasions, did not compare the control room data to the acceptance criteria in TI-28, and subsequently failed to recognize the change in the acceptance values. Failure to follow the requirements of 1-SI-OPS-000-002.0 is identified as a violation (327/92-03-01).

- Review of attachment 5 to TI-28 determined that a change in acceptance criteria was made to the attachment without following the requirements of Site Standard Practice SSP-2.3, ADMINISTRATION OF SITE PROCEDURES, Revision 7. SSP-2.3, requires that procedure changes that involve change in acceptance criterion shall be processed as an intent change. However, SSP 2.3 also allowed for processing of attachments to TI-28 without following the requirements of the SSP. This was allowed because the SSP stated in note 4 of Appendix F to SSP-2.3 that "these Attachments are controlled by requirements within their respective controlling document." A review of TI-28 by the inspectors concluded that no controls were in place to assure Attachment changes to TI-28 were properly processed. After identification of the problem, the licensee enhanced the requirements of SSP 2.3 to correct the problem. Failure to follow the requirements of SSP-2.3 in the processing of new acceptance criteria for a TS surveillance parameter is identified as a non-cited violation (327, 328/92-03-02). This violation is not being cited because the criteria specified in Section V.A of the Enforcement Policy were satisfied.

- The inspectors also noted that part of surveillance procedure 0-SI-SXX-068-155.0, REACTOR COOLANT FLOW VERIFICATION, Revision 1 was being used to determine RCS flow rate from the Eagle 21 racks in the Unit 1 auxiliary instrument room. The inspectors were informed that the procedure was being used by the technical support personnel as a part of the evaluation and corrective action for PER SQ921501. This resolution would provide for immediate RCS flow information and allow for continued unit operation. Later, in the inspection period, the inspectors were provided with a copy of the package for PER SQ921501 which included supporting information. During review of the package against the requirements of SSP-8.1, the inspectors questioned the licensee as to why a revision was not made to 0-SI-OPS-000-002.0 to include the PER package for resolution of the DN identified in the SI. The licensee stated that SSP-8.1 allowed for resolution of the test deficiency without revising the applicable test (1-SI-OPS-000-002.0). The inspectors determined that the licensee's technical approach to resolution of the DN was adequate; however, they considered that SSP-8.1, in this case, may have required test procedure revision for resolution of the DN. This concern was identified as a weakness in the implementation of SSP-8.1 requirements. Licensee management agreed to review this issue. The inspectors considered that the licensee's ongoing review of this issue, when the inspection period ended, would adequately resolve the concern.

(2) On February 10, 1992 while inspectors were monitoring unit 2 recovery from a reactor trip (paragraph 6.f.2), an inadvertent actuation of ESF systems occurred. During the performance of SI-93, REACTOR TRIP INSTRUMENTATION FUNCTIONAL TESTS, Revision 10, an attempt was made to close the reactor trip breakers. When the operator took the switch to close, the trip breakers immediately tripped back open, and an AFW actuation signal started the TDAFW pump (MDAFW pumps were already running for heat removal in mode 3).

The immediate opening of the trip breakers was due to the fact that the high negative neutron flux rate reactor trip signals from the previous trip had not been reset by the operators. Post event review by inspectors and the licensee revealed several contributing factors:

- Neither SI-93, nor plant shutdown procedures in use required operators to check or reset any reactor trip signals which were present.

- Operators did not take time to consider the status of the plant upon the reactor trip breakers. This is contrary to the requirements of AI-30, NUCLEAR PLANT CONDUCT OPERATION, Revision 36, paragraph 11.8, which requ[illegible] at before an operator performed an operation, the [illegible]ed response should be anticipated. Operators had sufficient indication to anticipate the problem if they had taken appropriate time to analyze plant conditions. The high negative rate reactor trip first out annunciator was in alarm and was not marked as a part of the SI-93 test. Operators assumed that these indications were not valid, and that the trip signal had been jumpered. No attempts were made to verify annunciator status with the SI or to discuss annunciator status with instrumentation personnel.

  This failure of the operators to analyze plant conditions prior to performing an operation is identified as a violation for failure to follow the procedural requirements of AI-30 (327, 328/92-03-03).

The actuation of the AFW system was caused by a MFW isolation signal which occurred upon opening of the trip breakers with a low average RCS temperature. SI-93 instructed technicians to install two jumpers to defeat these signals, but a jumper for one train became disconnected due to the disloc[illegible]ing of a "banana plug" from an "alligator clip". The type of jumper used in three out of four terminations could be easily disconnected. A more secure type of termination was used on the fourth contact, and was not susceptible to this type of disconnection. The licensee is reviewing the need to specify the preferred type of jumpers used for maintenance on safety-related systems.

(3) On February 11, the inspectors witnessed control room activities of Unit 2 restart, following the February 10 reactor trip. The major evolutions witnessed included approach to criticality and taking the reactor critical, power escalation from approximately 5 to 17 percent, secondary plant lineups, turbine roll and latching, and turbine trip testing. The inspectors considered the overall control of the startup activities to be adequate. Communications between the unit and the secondary plant operator were frequent and resulted in no sudden SG level perturbations. The use of a restart timeline, which detailed visually the progression of major activities, appeared to have aided the SOS and ASOS in verifying completion of startup steps.

The inspectors observed selected portions of the performance of GOI-2, PLANT STARTUP FROM HOT STANDBY TO MAXIMUM LOAD, Revision 73, including preparations to latch and roll the main turbine utilizing the EHC panel on control board M-2. During the evolutions, operators were aware that due to throttle valve leakage, turbine speed indicated approximately 150 rpm. Normal speed after latching is approximately 50 rpm. During performance of the GOI, the CR turbine operator noted that a required governor valve position limit lamp was not illuminating. After verifying the lamp bulb had not failed, turbine control personnel discussed the condition with the SOS. The limit light problem was determined to be an acceptable condition due to the increased turbine speed because of higher than normal throttle valve leakage. Turbine rollup evolutions then progressed. During performance of step V.C.31, the operators expected to witness the governor valves opening as the valve limiter was raised to 100 percent open. At the 100 percent limit position, all four governor valves still indicated closed. The CR turbine operator was instructed to decrease the valve limiter to zero by the ASOS. Upon further discussion, the operators concluded that the throttle valve leakage further inhibited the governor valves from opening until the reference speed was raised above the actual speed of the turbine. The inspectors attributed the failure of the governor valves to open as anticipated, to an unfamiliarity of the operators with regard to turbine governor valve control in conjunction with higher than normal throttle valve leakage. Once the operators became aware of the turbine responses to the abnormal throttle valve leakage, the governor valves were successfully opened.

Following turbine rollup to approximately 1800 rpm, the operators performed section V.C.49 of GOI-2 (a turbine overspeed oil trip test), which was required to be performed due to the turbine restart. During the test, the operators at the turbine front standard tripped the turbine by opening the turbine overspeed oil trip test valve, and recorded the oil pressure required to perform the trip. The inspector reviewed 0-PI-OPS-047-760.0, MAIN TURBINE OVERSPEED AND OIL SYSTEM TESTS, Revision 1, which was the procedure used by the local operator to perform the overspeed testing. This procedure contains more explicit instructions than GOI-2 for the overspeed oil trip test, such as, test acceptance criteria, required communications, and personnel responsibilities and cautions. The SOS requested the use of the PI for the overspeed test required by GOI-2 and to perform the other turbine trip tests detailed in the PI. The February 11 performance, included testing of overspeed trip mechanism oil pressure, vacuum trip, thrust bearing trip, and low bearing oil pressure trip. Each trip parameter is tested by holding the test lever on the front standard of the turbine to the test position (to preclude an actual turbine trip) and actuating the associated trip device through test valves. The difference between this test and the GOI-2 test is that no actual turbine trip is initiated.

During the inspectors review of the completed PI, several problems were noted. First, the inspectors determined that the performance of the PI was not logged in test awareness or operator logs as other tests are routinely monitored and tracked. Second, the overspeed test appeared to be being performed in accordance with GOI-2 by control room operators, whereas performance in the field was completed via the PI. As a result of the use of the two procedures during the evolution, the inspectors noted several steps in the PI which were not appropriately filled in by the control room operator. After discussions with operations management, the inspectors concluded that the procedure requirements were accomplished; however, a lack of attention to detail was noted with regard to control of the testing activities and completion of procedure documentation.

During the turbine testing, with the turbine operating at 1800 rpm, an unanticipated turbine trip first out annunciator came in (condenser vacuum low turbine trip). Operators first verified that the turbine had not tripped and determined the probable source of the alarm as the continuation of the turbine trip testing being performed per 0-PI-OPS-047-760.0. The operators contacted the operator performing the test and after some evaluation of the alarm, the test was allowed to continue. At this time, the inspectors concluded their observation.

0-PI-OPS-047-760.0 was reviewed with regard to annunciations of turbine trip alarms during testing. The inspectors reviewed annunciator wiring diagrams and trip setpoints and concluded that several of the trip tests had the potential to bring in a corresponding turbine first out annunciator during the test. The alarms in question could annuciate depending on the amount of time taken during steps in the procedure. With the exception of the thrust bearing trip test, the procedure does not identify important annunciation such that operators could expect the alarms during the turbine testing.

The inspectors reviewed the receipt of the unanticipated annunciation during the test in conjunction with the requirements of AI-30, NUCLEAR PLANT CONDUCT OF OPERATION, Revision 36. Step 11.8.3 details operator response to unexpected annunciators received during the performance of tests. The procedure states, in part, that if the evaluation (of the annunciator) reveals that the suspect alarm(s) should have been received, testing may continue, provided that the basis for continuing the evolution be logged and the procedure should be revised to address the annunciator problem prior to the next perf[illegible]e. The inspectors concluded that although operators di[illegible] the unexpected alarm prior to progressing with the te[illegible]ng, no log entry was made or procedure change request initiated as required by AI-30. The failure to make the required log entry and institute actions for a procedure change is identified as a second example of violation 327,328/92-03-03 for failure to follow the procedural requirements of AI-30.

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 components, 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.

(1) On February 7, 1992 the inspectors met with licensee personnel to discuss the status of the Fire Protection Program Improvement Plan. The inspectors were informed that the implementation of the improvement plan was progressing as scheduled, with the first phase of the plan to be completed by April 1, 1992. In addition, the licensee submitted a status report update to the plan to the NRC in a letter dated February 7, 1992. The plan update letter also addressed responses to comments made by the NRC to the plan in a letter from the NRC to the licensee dated November 13, 1992.

The inspectors reviewed the licensee's status of ongoing activities in addition to continuing to monitor compensatory measures taken by the licensee to satisfy TS requirements. These compensatory measures include continuous fire watches in several areas of the plant. Additional discussions have been held with both licensee and NRC management and the NRC intends to conduct a special inspection in the near future to review licensee corrective actions for the many deficiencies identified in the Fire Protection Program during the last year, along with review of the improvement plan actions to verify that they meet requirements.

(2) During a plant tour on February 14, the inspectors noticed that several safety-related pump room areas on elevation 669 were posted as contaminated with appropriate barriers established. The inspectors questioned licensee staff with regard to the noted condition, and were informed that room drains had backed up creating the contamination condition during the past 24 hours. The inspectors further questioned licensee personnel as to the reason that the drains overflowed and were not able to obtain an answer to the question. In addition, the inspectors asked if a problem evaluation report had been written to identify the problem. The inspectors were provided with a copy of a PER (SQPER920040) dated February 18, 1991. The inspectors will monitor licensee corrective actions associated with the PER.

The inspectors consider that a PER was the appropriate corrective action process to address the issue and noted that this process was not implemented until identified by management the following day. Based on this event and another example discussed in paragraph 5.b of this report, a weakness was identified with regard to licensee implementation of the problem evaluation report part of the corrective action process. The weakness involved unclear guidance to personnel as to when to initiate problem evaluation reports. Licensee management has reviewed the inspector's concern during this period and has begun implementation of additional actions to assure that personnel better understand when to use the PER part of the corrective action program.

(3) On February 18, during detailed tours with Auxiliary Building Operators, inspectors observed that the previous shift had failed to complete all rounds required by 1-PI-OPS-000-038.4, AUXILIARY BUILDING AUO DUTY STATION SHIFT RELIEF AND ROUND SHEETS, Revision 1. During the midnight shift, the Auxiliary Operator had been directed to complete the performance of a periodic surveillance on a MDAFW pump. This operation had required several hours of work, and left the operator inadequate time to complete the normal shift routine inspections of plant spaces and equipment. Discussions with licensee personnel revealed that due to a shortage of personnel, it was not uncommon for Auxiliary Operators to be tasked with other work which prevented them from completing these periodic inspections during an eight hour shift.

(4) During a plant tour on February 28, the inspectors noted what appeared to be a plastic bag of material located on the auxiliary building crane walkway which was operating over the spent fuel pool (Elevation 734). The inspectors questioned this practice and notified operations personnel of their concern. The SOS went to the crane location and determined that the bag in question contained light bulbs which were being changed out in the auxiliary building overhead prior to the crane operation which was observed by the inspector. Additional material was also identified on the crane walkways by the SOS.

After the event, the inspectors reviewed the administrative requirements for crane operation. The requirements were described in site standard practice SSP-6.6, SAFE PRACTICES FOR OPERATION OF OVERHEAD HANDLING EQUIPMENT, Revision 0. The practice required, in part, that the qualified operator perform a visual inspection to include removal of loose parts, tools, rags, paint chips, or other items that could fall off the crane. The inspectors discussed this requirement with licensee supervisory personnel and requested that a copy of the visual inspection report for preoperational checks prior to the inspectors observations be provided for review. Later that day, crane supervisory personnel provided the inspectors with the requested report and stated that the report had not been properly completed as required for the areas of inspection in question. The supervisory personnel also stated that a PER was being initiated to evaluate this problem. Licensee management also took immediate actions to assure that all crane operators were aware of their responsibilities prior to conducting crane operations. Failure to conduct a preoperational checkout of the auxiliary building crane prior to operation on February 28, 1992 is identified as a non-cited violation of SSP-6.6. (327, 328/92-03-04). This violation is not being cited because the criteria specified in Section V.A of the Enforcement Policy were satisfied.

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; 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.

Early in the period, during a review of Unit 2 RCS leak rates, the inspectors noted that operators did not have available to them immediate information that could be used to allow for a determination of an adverse trend of leakage into specific locations (i.e. the PRT, RCDT, and/or Accumulator Tanks). During the tour, the inspectors specifically were concerned with leakage trending information not being immediately available to operators for degraded components. These degraded components were weeping pressurizer code safety valves on both Unit 1 and 2, and leaking accumulator check valves on Unit 2. Although specific leakages were calculated as part of leak rate determinations, and the leak rates were well within TS limits, the inspectors noted that the completed procedures were routed for final reviews and disposition as soon as completed. A review of operator logs did not provide adequate leakrate information to resolve the inspectors concern.

This issue was discussed with management on several occasions during the inspection period. Licensee management stated that engineering personnel were trending the degraded component leakages; however, their review of the specific concern confirmed the inspector's issue. The inspectors consider this issue to be a weakness with regard to a lack of trending of important parameters for immediate operator use during operation with recognized degraded components.

Licensee management reviewed the inspectors issue and instituted a process where operators were provided access to trending data for several plant parameters. During the latter part of the period, the inspectors monitored trending information available to operators in the control room and noted that trend graphs had been made available to operators for trending of selected parameters.

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 February 9, 1992 the licensee made a call to the NRC as required by 10 CFR 50.72 concerning Unit 1 potentially being outside its design basis. The unit was operating at approximately 100% power (Mode 1) at the time. The licensee was performing routine operator surveillances when it was determined that total RCS flow may be lower that the TS limits (TS 3.2.5.c limit > or = 378400 gpm). Immediate action was to enter TS 3.2.5 ACTION statement at 1752 hours and then to dispatch personnel to the Eagle 21 racks in order to obtain a more accurate RCS flow information. After determination of RCS flow indication at the Eagle racks (flow determined to be approximately 391,000 gpm) the licensee exited the TS ACTION statement at 2041 hours. The licensee then made a second call to the NRC at 2120 hours and rescinded the call that was initially made above.

The resident inspectors responded to the site and monitored licensee actions with respect to determination as to how the problem was discovered and licensee immediate actions to determine present RCS flow. Some problems were identified which are further discussed in paragraph 3.a.(1). The licensee documented the event with a problem evaluation report and also commenced an incident investigation. The PERP for the incident investigation was monitored by the inspectors and is discussed in paragraph 6.d. The licensee will submit an LER for this event.

(2) On February 10, 1992 the licensee made a call to the NRC as required by 10 CFR 50.72 regarding a reactor trip of Unit 2 from approximately 90% power. The reactor trip, which occurred at 0528 hours, was the result of a turbine trip. The turbine panel first out annunciator indicated that the turbine trip was caused by a turbine overspeed condition; however, preliminary information did not indicate that a turbine overspeed condition occurred. After the trip signal, all systems functioned as required. Reactor temperature and pressure stabilized after the trip at approximately 544 degrees F and 2235 psig respectively. The unit was maintained in MODE 3 with the two motor driven auxiliary feedwater pumps maintaining SG levels (steaming to the main condenser for decay heat removal). The licensee convened a post trip review team to evaluate the trip. Their results and conclusions are discussed in paragraph 6.b. The inspectors monitored restart of the unit after completion of required corrective actions. This effort is discussed in paragraph 3.a.(2). The licensee will submit an LER for this event.

(3) On February 10, 1992 the licensee made a call to the NRC as required by 10 CFR 50.72 regarding an inadvertent ESF actuation on Unit 2 which was in Mode 3 at the time. The ESF actuation occurred during performance of SI-93, REACTOR TRIP INSTRUMENTATION FUNCTIONAL TESTS, Revision 10. During the performance of SI-93, the reactor trip breakers would not close, and an AFW pump auto start signal occurred. The apparent cause of the reactor trip breakers not closing was due to a failure of operators to reset the high negative neutron flux rate trip. The AFW actuation was caused by a jumper connection which came loose. The jumper was installed as part of SI-93 to defeat the signal. The inspectors monitored licensee operator performance during the event from the control room and noted several problems which are discussed in paragraph 3.a.(2). The licensee is conducting an incident investigation and will submit an LER for this event.

(4) On February 10, 1992 the licensee made a call to the NRC as required by 10 CFR 50.72 regarding a manual ESF actuation on Unit 2. During withdrawal of shutdown bank control rods in preparation for unit startup, the operator observed that the group demand step counter for Bank "D" was reading in error. TS 3.1.3.3 requires, in part, that group demand position shall be OPERABLE and capable of determining within + or - 2 steps the demand position for each shutdown control rod not fully inserted. The ACTION for TS 3.1.3.3 requires that with less than the above required group demand position indicator(s) OPERABLE, immediately open the reactor trip breakers. The operator determined that the Bank "D" step counter was inoperable and immediately opened the reactor trip breakers from the control panel which was considered to be a manual ESF actuation. The inspectors reviewed the licensee actions and consider that all TS requirements were met. The licensee will submit an LER for this event.

Within the areas inspected, two violations and two non-cited 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:

a. On February 21, inspectors observed the performance of PM-41302000, RHR PUMP ROOM COOLER 2AA INSPECTION. The PM consisted of removing pipe caps from the end head of the 2A RHR pump room cooler and inspecting for fouling. A problem was noted in that no attempts were made to drain the ERCW header prior to removal of the cooler caps. Mechanical maintenance personnel instead attempted to drain the isolated header through removal of the first cap. The high static head and volume in the header resulted in a large amount of ERCW sprayed into a plastic bag, and some water sprayed in the RHR pump room floor. Inspectors departed the area for approximately fifteen minutes, and upon returning found that maintenance personnel were bolting the cover back onto the cooler. When asked if the inspection had been completed, maintenance personnel replied that the metallurgical inspector had signed off the cooler inspection as satisfactorily free from fouling based on the clear and unfouled water seen when the attempt was made to remove the pipe cap. However, the chemistry inspector had not yet signed off on the inspection, since he did not get an opportunity to look into the cooler head. Maintenance personnel had to later reopen the cooler to allow a chemist to complete the remaining portion of the inspection. Maintenance documentation was also reviewed with no deficiencies noted.

b. On February 26 and 27 the inspectors monitored the activities associated with work request number C076374, RCS LOOP 1 Delta T. The purpose of the work request was to update a parameter in loop 1-T-68-25 in order to address a problem where frequent nuisance annunciation of a condition was being observed by operators. This problem was initially identified as a part of hot leg streaming problems, and the annunciation taken out of scan in accordance with SSP-12.53 on February 22. The inspectors monitored the craft briefing for the work prior to performance, monitored actual work in progress in the Unit 1 auxiliary instrument room, discussed the work method with the system engineer, and reviewed selected completed procedures in the work package which included:

- Surveillance Instruction 1-SI-IFT-068-025.2, FUNCTIONAL TEST OF DELTA T/TAVE CHANNEL II RACK 6 LOOP T-68-25 (T421/422), Revision 2. This instruction was used to remove the loop from service and for return of the loop to service.

- Maintenance Instruction 0-MI-IXX-099-001.0, EAGLE 21 SUBROUTINE INSTRUCTION, Revision 0. This instruction was used to update the parameters in the EAGLE 21 system.

- Surveillance Instruction 1-SI-IFT-003-519.2, FUNCTIONAL TEST OF ENVIRONMENTAL ALLOWANCE MODIFIER (EAM)/TRIP TIME DELAY (TTD) PROTECTION SET II, Revision 1. This instruction was used to remove EAM/TTD loop 1-L-519/549 from service and to return the loop to service.

The inspectors noted that these procedures were well coordinated with work instructions included in the work order package, personnel were knowledgeable in performance of duties, and specific procedural controls and technician performance in accomplishment of the activity was very good.

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. Inspection areas included the following:

a. On February 13, 1992 inspectors observed the routine shift conduct and documentation of 0-PI-OPS-301-001.0, ANNUNCIATOR ALARM AND/OR P-250 COMPUTER POINT DISABLEMENT, Revision 2. Checks of P-250 and Unit 0/1 annunciator computer points out of service were reviewed. The operators satisfactorily obtained computer printouts of points out of service, and correctly verified them against the index of points authorized to be disabled in accordance with the PI.

However, several problems were noted in the actual records (Appendix C of the PI) available in the Unit 1 logbook. Several annunciator points were signed off in the index as being returned to service, but the supporting records behind the index were not signed off to document the return to service. Also, annunciator point number 369, window 34 on XA-55-5A, (Narrow Range RTD Failure Loop 3) was listed as out of service, with the supporting record indicating that an evaluation per 10 CFR 50.59 was required. However, no 50.59 documentation was attached to the record.

Licensee investigation revealed that the 50.59 review had not been completed, although it had been requested when the annunciator was removed from service on December 30, 1991. The annunciator had been authorized to be disabled, since it was considered a nuisance annunciator which occurred due to the hot leg streaming problems that the plant had been experiencing following the cycle 5 refueling outage. Although the PI and site procedure SSP-12.53, ANNUNCIATOR DISABLEMENT, Revision 1, both allow for the SOS to authorize disablement of a nuisance alarm prior to a 50.59 review, over six weeks had elapsed without the review being completed. The licensee subsequently completed a 50.59 review on February 18, 1992.

This failure to perform a 50.59 review for the removal of a safety-related annunciator from service until identified by NRC inspectors is a violation of SSP-12.53 (327, 328/92-03-05).

The inspectors also noted that, on February 22, the licensee disabled annunciator point 363 for the loop 2 narrow range RTD failure alarm using the same methodology. In this case, the licensee deferred the completion of a 50.59 evaluation pending completion of a setpoint change of the alarm circuitry algorithm. This change was completed on February 27, and the annunciator was returned to service. The inspectors consider that licensee 50.59 review, in this case, should have been initiated as part of the total corrective action plan. Licensee management agreed to review the inspectors' concern.

b. On February 7, the inspectors noted that ventilation dampers to the 1B1 and 1B2 480 volts SDBRs were isolated and ventilation in the general area appeared blocked. The dampers are normally held open by fusible links which, when melted by electric heaters actuated by area fire detection devices, close the dampers to the required condition. No work requests were readily visible on the equipment indicating any planned corrective activity. The inspector informed the Unit 1 ASOS of the problem and discussed operability of the SDBR ventilation system and its effect of the shutdown boards. Whereas the board room operability is based on exceeding a 104 degrees F limit and the fire dampers were failed to their conservative closed position, the inspector did not consider the SD board operability in question.

The above activities were reviewed in conjunction with performance of SI-234.6, TECHNICAL SPECIFICATION FIRE DETECTORS, Revision 13. The SI verifies, in part, detector and alarm circuit supervision operability and operational check of non-supervised circuits between fire protection panels and actuated equipment. During the performance of SI-234.6 on January 28, 1992, personnel performance problems occurred which resulted in the inadvertent actuation of the fire dampers. A problem occurred during testing on zone 184, which includes the areas monitored in the affected SDBRs. The testing was performed on numerous zones at a fire protection panel and was very repetitive in nature. However, when the consecutive testing on zone 184 was to begin, a required breaker configuration change, detailed in the procedure, was not performed which resulted in the inadvertent actuation of the dampers. Immediate corrective actions for the event included stopping the test, notification of operations, verifying all actuated equipment, and initiating WR C052219 to replace the fusible links. SSP-8.1, CONDUCT OF TESTING, Revision 2, Section 3.12.7, requires, in part, that test performers adhere to test instructions and follow the instructions step by step unless specifically allowed by the test instruction. The requirements of SSP-8.1 were not adhered to in that a procedural step in SI-234.6 was not performed which resulted in an inadvertent actuation of fire protection equipment. The failure to follow the test instruction is identified as a non-cited violation of SSP-8.1 (327, 328/92-03-06). This violation is not being cited because the criteria specified in Section V.A of the Enforcement Policy were satisfied.

The inspectors also discussed the decision of the involved personnel in not identifying the event on a PER. The licensee initially indicated that they considered the event isolated and that appropriate corrective actions (i.e., the initiation of a WR to replace the fusible links) were adequate. The inspectors questioned whether the issuance of a WR would address the cause of the inadvertent actuation. During a review of the completed SI-234.6 procedure with electrical maintenance personnel, the inspectors identified an inappropriate method by which the surveillance personnel were performing second party verifications. Numerous second party and independent verifications are required to be performed for each fire protection zone in SI-234.6. The method utilized by electrical maintenance personnel to perform the work verifications was to first complete all of the first party signoffs for a given zone (both independent and second party), and then when the actual work was completed, the second party signoffs were completed in a similar manner. The inspectors concluded that this method resulted in the second party verifications not being performed in accordance with AI-37, INDEPENDENT VERIFICATION. This is identified as an additional example of a violation previously identified in NRC Inspection Report 327, 328/91-31 were identified. In addition to the above problem, the inspectors identified one step in the procedure had been incorrectly performed, rather than marked not applicable per the procedure. Due to the previous observations, the inspectors considered that if a PER had been initiated due to the original personnel performance problems, the licensee may have been able to identify and correct the identified procedural performance problems. This is a second example of a weakness identified with regard to licensee implementation of the problem evaluation report portion of the corrective action program which is discussed in in paragraph 3.b.(2).

Within the areas inspected, one violation, one non-cited violation, and an additional example of a violation identified in NRC Inspection Report 327, 328/91-31 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.

a. On February 6, 1992, the inspectors monitored a scheduled PORC meeting. The items reviewed by the committee included: a safety evaluation oversight for a DCN to correct an inrush voltage problem for radiation monitors 0-RE-90-133 and 0-RE-90-134; review of LERs 327/91009, revision 1 and 327/91016 revision 1; and review of Special Test Instruction (STI) -149, Centrifugal Charging Pump Gas Vent, revision 0. The inspectors noted that during the review of the radiation monitor safety evaluation, plant management expanded discussion of the implementation aspect of work to be performed as corrective action for the issue. All items which were presented to the committee were approved after member review.

b. On February 10, 1992 the licensee held a special PORC to evaluate the post trip report for the Unit 2 reactor trip which occurred earlier that day (see paragraph 3.f(2)). The report had been prepared by the post trip review team in accordance with site standard practice SSP-12.9, INCIDENT INVESTIGATIONS AND ROOT CAUSE ANALYSIS, Revision 1. The inspectors monitored the review and noted the thoroughness of the report and licensee management/review team interaction with regard to identification of corrective actions required prior to authorization of unit restart.

c. On February 20, 1992 inspectors attended a meeting of the NSRB, which functions as an independent review and audit organization as required by TS 6.5.2. Numerous issues were discussed between licensee senior management and the NSRB, including current licensing issues, quality assurance findings, corrective action program status, chemistry and radiological concerns, and outage management. Licensee management was open and forthright with the board, and accurately related past plant problems and the status of their resolution.

d. On February 20 and 21, 1992 the licensee conducted a PERP meeting associated with incident investigation II-S-92-011, INDICATED LOW REACTOR COOLANT SYSTEM (RCS) FLOW. The event is discussed in paragraph 3.f.(1). The inspectors monitored the PERP interaction with plant management and noted a continuing strength with regard to the review process and the manner in which root causes for events are thoroughly discussed and understood prior to adjournment of the meeting.

e. On February 25, 1992 the inspectors monitored the licensee's PERP meeting associated with incident investigation II-S-92-013, UNPLANNED ESF EVENT - FEEDWATER ISOLATION. The event is discussed in paragraph 3.a.(2). The licensee's investigations were thorough in determining the cause and corrective actions for the feedwater isolation occurring when a jumper connection came apart. However, inspectors considered that additional management attention should have been focused on operator performance during the event.

f. On February 26, 1992 the inspectors monitored the licensee's PERP meeting associated with incident investigation II-S-92-009, on controlled drawing discrepancies. The issue was also discussed in NRC Inspection Report 327,328/92-02, in which, a violation was identified for drawing problems found by the NRC and the licensee's QA organization. The inspectors considered the investigation complete and that all causes for the event were appropriately identified. The effectiveness of the corrective actions will be considered during review of the violation in a subsequent report.

Within the areas inspected, no violations were identified.

7. Licensee Event Report Review (92700)

The inspectors reviewed the LERs 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.

(Closed) LER 327/90-22, Sequoyah Unit 1 Reactor Trip as a Result of a Turbine Trip Caused from Corroded and Shorted Terminals on the Spare (A Phase) Main Transformer's Gas Relay. The licensee concluded that the root cause of the subject event was corroded and shorted terminals on the spare transformer's gas relay. The corrosion shorted the gas relay, resulting in the initiation of the turbine trip signal. Procedure problems also contributed to not identifying and correcting the gas relay corrosion problems prior to the event. Additionally, the licensee identified the need for improved and clear definition of responsibilities between T&CS and plant maintenance. The inspectors reviewed the corrective actions taken for the event which included the incorporation of maintenance and preventative maintenance procedures to properly install and checkout the spare main transformer, evaluations of the sensitivity of the flapper in the gas relay, and inspection of the remaining transformers for abnormalities. The inspectors considered that the procedures were adequate to place the spare transformers in service and verify proper relay operation. The inspectors did identify during the review that both the old and recently revised version of 1-MI-EXX-241-024.0, PLACEMENT OF SPARE MAIN TRANSFORMER IN SERVICE, were available for use in the licensee's procedure control offices. Once informed, the licensee took actions to place the outdated version on administrative hold pending removal. In addition, the inspectors reviewed the implementation of TACFs 1-90-45-241 and 2-90-49-241, for units 1 and 2 respectively, which eliminated the sudden pressure transformer differential generator trip by their gas relay's flow switch. These TACFs were based on the gas relay's trip function being in parallel with the sudden pressure trip function and were incorporated to resolve recent spurious sudden pressure actuations. The Unit 1 TACF was subsequently closed due to permanent disablement of the sudden pressure trip circuitry. The Unit 2 TACF plans to be resolved during the upcoming Unit 2 cycle 5 refueling outage. The inspectors also discussed improvements made in communications between T&CS and site organizations and specifically, communications necessary for placement of the subject transformers in service. The inspectors considered the corrective actions taken for the LER to be adequate to preclude recurrence.

(Closed) LER 327/91-17, Operation with an Inoperable Lower Containment Radiation Monitor Because of the Inlet Valve Being Isolated. The event involved discovery on a valve being closed by chemistry personnel in a TS required flowpath. Immediate corrective action was to reopen the valve and conduct the necessary test to verify operability. An event investigation was conducted and the licensee concluded that the cause of the event was related to personnel performance weaknesses in addition to procedural inadequacies. Corrective actions included reinforcement of personnel expectations from a "lessons learned" perspective. In addition, procedures were enhanced and chemistry personnel performance expectations were better communicated through administrative procedures enhancement and ongoing Sequoyah performance effectiveness initiatives. The inspectors attended the licensee's PERP meeting and reviewed corrective actions.

(Closed) LER 327/91-19, Emergency Diesel Generator Started When the Start-Stop Handswitch 0-HS-82-104 Was Inadvertently Bumped. The event involved bumping of a hand switch on a Emergency Diesel Generator Panel in the main control room due to a engineer being too close to the panel (in a red carpet area) when conducting business in the control room. Immediate corrective action was taken by operator to place the EDG back into a standby condition. Additional corrective actions which have been instituted included signs instructing personnel, other that operators, not to stand on red carpeted areas, and rearrangement of the SOS workstation to better allow for personnel to do business at this workstation without being too close to EDG control panels. The inspectors reviewed the event and have monitored licensee corrective actions.

(Closed) LER 328/91-04, Computer point out of scan on the P-250 computer as a result of not maintaining configuration control. This LER concerned ar event where TS 4.1.3.2 requirements for comparing rod position indications were not complied with due to the fact that operators were not aware that the rod deviation alarm feature of the P-250 computer had been disabled. Licensee corrective actions included generation of listings of TS related computer points, additional P-250 administrative controls, and setpoint changes to the P-250 alarm setpoints. Inspectors reviewed corrective actions and found that all actions had been completed. Additionally, inspectors reviewed current P-250 disabled alarm status and found it to be documented and tracked on a shiftly basis by unit operators.

Within the areas inspected, no violations were identified.

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

a. (Closed) IFI 327, 328/89-14-02, Change to corrective -tion in Element Report 30202 concerning equipment susceptibility to past overvoltage conditions. The issue involved a change in the licensee's corrective action for equipment susceptibility to past overvoltage conditions. The change was from test/analysis to a failure trend analysis method in order to evaluate component failure from this condition. The inspectors reviewed the licensee failure trending procedure along with component failure information from 1989 to present. The information reviewed did not identify any pattern of failure of electrical components from overvoltage conditions. In addition, the licensee has instituted corrective actions to eliminate future high voltage conditions. These corrective actions include installation of new common service station transformers with automatic tap changers. One transformer has been installed, with two transformers to be installed. The inspectors consider that licensee corrective actions for closeout of this issue are adequate.

b. (Closed) URI 327, 328/89-15-07, Weakness in Safety Evaluation Program. The issue involved weaknesses identified in the licensee's method of implementing 10 CFR 50.59 requirements, the independent qualified reviewer program, and experience review feedback to the safety evaluation process. Licensee corrective actions for these weaknesses were discussed in inspection reports 327, 328/90-01, 91-06, and 91-08. Those reviews concluded that although corrective actions were taken, some weaknesses relating to safety assessments and evaluations being adequate still remained. The licensee has further enhanced the 50.59 review process during the last year. A review of the 50.59 program was accomplished by the NRC in January 1992. The results of that inspection were documented in inspection report 327, 328/92-02. That review concluded that the licensee has adequately implemented the requirements of 10 CFR 50.59.

c. (Closed) URI 327, 328/89-19-02, Key Control Program. The issue involved use of an uncontrolled key to the rod control cabinets. The licensee issued CAQR SQN890465 to address the problem of the uncontrolled key. The issue was further reviewed by the inspectors and discussed in NRC Inspection Report 327,328/89-21. As part of the initial corrective action for the problem, the licensee required the return of uncontrolled keys. Upon the collection of numerous keys, the inspectors raised additional concerns about a generic problem of key control at the site. The licensee expanded the CAQR due to the concerns to more appropriately address the overall issue. The inspectors also determined, in inspection report 89-21, that the original instance of the uncontrolled usage was isolated; however, the inspectors did identify a weakness at that time in the corrective action process with regard to this issue.

During this inspection period, the inspectors reviewed the licensee's current key control process and visually inspected key control areas. Corrective actions for the CAQR were also reviewed which included upgraded key control procedures for operations, radiological, and maintenance areas. The inspector also verified proper performance of numerous operations key audits. As a result of the inspectors review, no instances of inappropriate key control and usage were noted, and procedural controls appear adequate to control site accessibility requirements.

d. (Closed) VIO 327, 328/90-01-01, Failure to Perform a Safety Evaluation for an Emergency Procedure Change. The violation involved making changes to plant EOPs without first properly evaluating the change for unreviewed safety concerns pursuant to 10 CFR 50.59. Additionally, Westinghouse was not consulted on the change, and no reviewing or documenting of the deviation from the standard WOG EOP basis document was performed. Corrective actions included changes to administrative instructions for processing EOP changes to require Westinghouse concurrence for changes which deviate from WOG guidelines, PORC review of all EOP changes, and training of personnel concerning the management of EOP changes. Also, a 50.59 review was completed and appropriate changes were made to the FSAR. Licensee corrective action was reviewed and found to be appropriate and properly implemented.

e. (Closed) IFI 327, 328/90-03-06, Long Term Cooldown Corrective Action. The issue concerned hardware modifications needed due to problems in excessive plant cooldown following reactor trips, and was an outstanding corrective action remaining from violation 327,328/88-35-01. The licensee committed to install changes to the steam dump control system in order to improve system response. The inspectors reviewed maintenance documentation and found that these changes were completed on February 16, 1989 for Unit 1, and March 24, 1989 for Unit 2.

f. (Closed) URI 327, 328/90-14-01, Plant Discrepancy Requiring a 10 CFR 50.59 Evaluation. This URI involved an issue between the NRC and the licensee over whether a 50.59 evaluation is required when a facility change is made which is not a permanent facility change. The specific instance was the installation of an incorrect sized containment spray pump impeller, with the development of a JCO, but not a 50.59 evaluation, until impeller replacement could be completed at the next outage. The inspectors reviewed the current status of the 50.59 program by discussions with licensee management, and as documented by a recent 50.59 program inspection (Inspection Report 327, 328/92-02). Based on this review, this issue is resolved, since a temporary facility change of this nature would receive a 50.59 review under current program criteria.

g. (Closed) URI 327, 328/88-12-04, Concerns with the Generation of Containment Design Basis Accident Response (CDBAR) Spectra. This URI was associated with the generation of containment design basis accident response Spectra. It involved verification of a double differentiation technique used in the computer code for CDBAR and certain aspects of the response obtained from the analysis. TVA responded to the NRC in letters dated, November 9, 1989 and June 11, 1990. Following NRC staff review of the submittals, it was concluded that the licensee adequately addressed the staff's concerns identified in the URI. The details of review were completed via TAC No. 79863 on April 22, 1991.

h. (Closed) URI 327,328/88-12-05, ERCW Pumphouse Foundation, and URI 327,328/88-12-09, ERCW Pumping Station Access Cells. The subject URI's concerned the ERCW pumping station and access cells which are seismic category I structures. Due to ERCW system piping and conduit being routed through access cells in passing from the ERCW pumping station to other safety-related buildings, concerns were raised regarding the boundary conditions and performances assumed in the analysis and design and the effect on the as-built structure. To ensure the design and adequacy of the as-built system and related structures, a number of meetings were held, beginning in 1987 to discuss the issues. The licensee's response to these issues has since been evaluated by the NRC staff. The staff concluded that the structural adequacy of the pumphouse and the access cells has been demonstrated, and that the as-built condition of the foundation would not effect the ERCW equipment qualification and piping. The details of the review were contained in an SER forwarded from NRR to Region II by letter dated August 9, 1991 for both URI 88-12-05 and URI 88-12-09.

Within the areas inspected, no violations were identified.

9. Exit Interview

The inspection scope and results were summarized on March 3, 1992 with those individuals identified by an # in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee.

| Item Number | Described and Reference |
|---|---|
| 327/92-03-01 | Violation for failure to follow the requirements of 1-SI-OPS-000-002.0 (paragraph 3.a.(1)). |
| 327, 328/92-03-02 | NCV for failure to follow the requirements of SSP-2.3 (paragraph 3.a.(1)). |
| 327, 328/92-03-03 | Violation for failure to follow the procedural requirements of AI-30 (paragraphs 3.a.(2) and (3)). |
| 327, 328/92-03-04 | NCV for failure to conduct a preoperational checkout of the auxiliary building crane prior to operation on February 28, 1992 as required by SSP 6.6. (paragraph 3.b.(4)). |
| 327, 328/92-03-05 | Violation for failure to follow the procedural requirements of SSP-12.53 in that an evaluation pursuant to 10 CFR 50.59 was not performed in a timely manner (paragraph 5.a). |
| 327, 328/92-03-06 | NCV for failure to follow the requirements of SSP-8.1 in that test performers failed to adhere to test instructions and subsequently. caused an inadvertent actuation of fire protection equipment (paragraph 5.b). |

Also, an additional example of violation 327, 328/91-31-01 was identified. The example involved a failure to follow the requirements of AI-37 in that second party verification was not performed as required during performance of the fire protection surveillance test (paragraph 5.b).

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.

10. List of Acronyms and Initialisms

AFW - Auxiliary Feedwater
AI - Administrative Instruction
ASOS - Assistant Shift Operations Supervisor
AUO - Auxiliary Unit Operator
CAQR - Condition Adverse to Quality Report
CDBAR- Containment Design Basis Accident Response
CFR - Code of Federal Regulations
CR - Control Room
DN - Deficiency Notice
DRP - Division of Reactor Projects
EAM - Environmental Allowance Monitor
EDG - Emergency Diesel Generator
EHC - Electro-hydraulic Control
EOL - End of Life
EOP - Emergency Operating Procedure
ERCW - Essential Raw Cooling Water
ESF - Engineered Safety Feature
FSAR - Final Safety Analysis Report
GOI - General Operating Instruction
GPM - Gallons per Minute
IFI - Inspection Follow-up Item
JCO - Justification for Continued Operation
KV - Kilovolt
LCO - Limiting Condition for Operation
LER - Licensee Event Report
MDAFW- Motor Driven Auxiliary Feedwater
MFW - Main Feedwater
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
NSRB - Nuclear Safety Review Board
PER - Problem Evaluation Report
PERP - Plant Evaluation Review Panel
PI - Periodic Instruction
PM - Periodic Maintenance
PORC - Plant Operations Review Committee
PRT - Pressurizer Relief Tank
PSIG - Pounds per Square Inch Gauge
RCS - Reactor Coolant System
RCDT - Reactor Coolant Drain Tank
RHR - Residual Heat Removal
RPI - Rod Position Indication
RPM - Revolutions Per Minute
RTD - Resistance Temperature Detector

RWP - Radiation Work Permit
SDBR - Shutdown Board Room
SER - Safety Evaluation Report
SG - Steam Generator
SI - Surveillance Instruction
SOS - Shift Operating Supervisor
SRO - Senior Reactor Operator
SQN - Sequoyah Nuclear (Plant)
SSP - Site Standard Practice
STI - Special Test Instruction
TAC - Technical Assignment Control
TACF - Temporary Alteration Control Form
TAVE - Average Reactor Coolant Temperature
T&CS - Transmission and Customer Service
TDAFW- Turbine Driven Auxiliary Feedwater
TI - Test Instruction
TS - Technical Specifications
TTD - Trip Time Delay
TVA - Tennessee Valley Authority
URI - Unresolved Item
V - Volt
WOG - Westinghouse Owners Group
WR - Work Request