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

Report Nos.: 50-327/92-30 and 50-328/92-30

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: August 30 through September 26, 1992

Lead Inspector: Paul J. Kellogg for
~~W. E. Holland, Senior~~ Resident Inspector 10/2/92
Date Signed

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

Approved by: Paul J. Kellogg
Paul J. Kellogg, Chief, Section 4A
Division of Reactor Projects 10/2/92
Date Signed

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.

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Results:

In the area of Operations, good performance was noted with regard to operator control of a Unit 2 secondary induced transient during a rapid power reduction (paragraph 3.a).

In the area of Security, an Unresolved Item was identified for determination of licensee compliance with the Security Plan with respect to Protected Area Lighting Deficiencies (paragraph 3.e).

In the area of Maintenance/Surveillance, an Unresolved Item was identified concerning possible installation of tags/labels contrary to Site Standard Practice - 6.56 (paragraph 4.b).

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
*M. Cutlip, Site Representative, Corporate
*T. Flippo, Site Quality Assurance Manager
*J. Gates, Technical Support Manager
*L. Hardin, Shift Operating Supervisor
*H. Harper, Site Security Manager
*C. Kent, Radiological Control Manager
*P. Lawrence, Shift Operating Supervisor
*M. Lorek, Operations Superintendent
*P. Lydon, Operations Manager
*J. Proffitt, Compliance Licensing Engineer
R. Rausch, Modifications Manager
*H. Rogers, Acting Technical Support Manager
*R. Salisbury, Public Relations
*J. Setliffe, Security Supervisor
*J. Smith, Regulatory Licensing Manager
*R. Thompson, Compliance Licensing Manager
*P. Trudel, Nuclear Engineering Manager
*T. Van Huis, Assistant Shift Operating Supervisor
*P. Wallace, Site Support 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.

On September 2, Mr. E. W. Merschoff, Director, Division of Reactor Projects, Region II, visited the Sequoyah Nuclear Plant. Mr. Merschoff discussed inspection activities with the resident inspectors, toured the plant, and held discussions with senior plant management.

On September 11, Mr. A. F. Gibson, Director, Division of Reactor Safety, Region II, visited the Sequoyah Nuclear Plant. Mr. Gibson discussed inspection activities and toured the plant with the resident inspectors, and held discussions with senior plant management.

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

2. Plant Status

Unit 1 began the inspection period at approximately full power. The unit operated at power for the duration of the inspection period.

Unit 2 began the inspection period at approximately 60 percent power. The unit was returning to power following repairs to both main feedwater pumps. Full power was achieved on August 31. On September 3, Unit 2 conducted a load follow to 75%. The unit resumed full power operations later that day. On September 4, the unit reduced power to approximately 1 percent due to a fire affecting the B main transformer. The event is discussed in paragraph 3.f(2). After repairs were completed, the unit returned to power operation on September 7 and operated at power for the remainder of the inspection period.

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 September 4, 1992, the inspectors responded to the site to monitor an event in which, at 2:30 a.m., a NOUE was declared for Unit 2. A small fire was identified on a bushing on the B phase of the Unit 2 main bank transformer which lasted greater than 10 minutes. The CR operators were informed of the fire at 2:14 a.m. by fire operations personnel in the switchyard. Details of this event are further discussed in paragraph 3.f.(2). The inspector reviewed the changes to plant parameters which occurred during the event and the actions taken by the operators. Specifically, operator actions with regard to the anticipation of a possible reactor trip following isolation of the intermediate pressure heater strings were excellent. Operator response was timely in recovering decreased SG levels during the transient. The inspectors considered these operator actions an example of good operator performance.

(2) On September 14, 1992, during a routine tour of the CR boards, the inspectors identified an abnormal indication on the Unit 1 number 2 RCP lower oil cooler. CR indication 1-FS-70-108, Lower Oil Cooler 2, was indicating off-scale high (greater than 6 gpm). Each RCP has both an upper and lower cooler which is supplied by component cooling water. The inspectors informed the unit operator of the condition. The operator determined that the indication was not a stuck CR gage and verified that all other CR board RCP indications and alarms appeared normal, including the upper oil cooler for the # 2 RCP. The unit operator then escalated the issue to his immediate supervision. The lower radial bearing temperatures were checked via the plant computer printout for the parameter. The temperatures for RCP 1 through 4, respectively, were 124, 166, 127, and 135 degrees F. This indicated that the suspect # 2 RCP may have been experiencing an oil cooling water supply problem; however, the RCP temperature shutdown limit of 200 degrees F was not exceeded. WR C0126695 was initiated to troubleshoot the problem. The inspector verified operators were monitoring the appropriate temperatures until the WR was performed.

On September 17, the licensee made a containment entry to troubleshoot the issue and identified that the high flow condition was due to the lower cooler flow control valve needing adjustment. It was also discovered that the thermocouple to the # 2 RCP lower radial bearing had high electrical resistance and was causing a false indication of an elevated temperature. The inspectors concluded that the problems were adequately addressed and corrective actions were taken in a timely manner.

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.

On September 24, 1992, during a backshift tour of the plant protected area in the vicinity of the Emergency Diesel Generator building, the inspectors noted that several protected area lights were not working. In addition, several other protected area lights along the back protected area fence were blinking on and off in an erratic manner. The inspectors discussed this condition with licensee security personnel and management and were provided with a copy of the latest weekly surveillance inspection procedure (0-PI-SQS-000-676.W, PROTECTED AND VITAL AREA INSPECTION, Rev. 0). This procedure identified 13 lighting deficiencies and also noted that these deficiencies were identified as being assigned to service request 13607 for implementation of corrective action. The inspectors reviewed several of the deficiencies and determined that they had been identified as problems for several months. During this timeframe, the licensee had been taking compensatory measures for the lighting degradation which involved increased vehicle patrol of the protected area. The inspectors were reviewing the compensatory measures requirements when the inspection period ended. This issue is identified as unresolved

(URI 327, 328/92-30-01, Determination of licensee compliance with the Security Plan with respect to Protected Area Lighting Deficiencies) pending completion of the inspectors review.

f. Licensee NRC Notifications

(1) On August 31, the licensee made a four hour non-emergency notification as required by 10 CFR 50.72 concerning an inadvertent ESF actuation. At 10:16 a.m., the blackout relay for the 1BB CCP was inadvertently actuated causing an annunciation in the main control room of the "6.9 KV SHUTDOWN BOARD LOGIC PANEL 1BB LOAD STRIPPING RELAY OUT OF SYNC alarm. The 1BB CCP was in service at the time of the event and continued normal operation throughout the event. The licensee determined that had the CCP been out of service, actuation of this relay would have caused the pump to automatically start. The relay was accidently actuated during activities involving Operations personnel removal of temporary stick-on labels located in the logic panel cabinets. No other relay devices were affected.

(2) On September 4, the licensee made a call to the NRC as required by 10 CFR 50.72 for entry into the site emergency plan. At 2:30 a.m., a NOUE was declared for unit 2 due to the identification of a small fire on a bushing on the B phase of the Unit 2 main bank transformer which lasted greater than 10 minutes. The fire was identified at 2:14 a.m. by fire operations personnel in the switchyard. Preliminary information indicated that a failure in a neutral ground bushing caused transformer oil to ignite, producing an approximate two foot high flame. The heat load of the fire was not enough to automatically actuate fire detection or suppression on the transformer. The licensee commenced a unit shutdown from 100% power at 2:20 a.m. in accordance with their abnormal operating instructions in order to unload the affected transformer. After several attempts, the fire was extinguished with dry chemicals at 2:32 a.m. The B main transformer was then cooled with hand-held fire lines to prevent re-ignition. The licensee established stable reactor conditions in Mode 1 at approximately 8 % power, and terminated the NOUE at 2:50 a.m.

At 2:56 a.m., all three strings of intermediate pressure feedwater (FW) heaters (2, 3, and 4 IP heaters) automatically isolated as a result of high levels following the rapid unit shutdown (approximately 5% per minute). Isolation of the FW heaters caused a loss of suction to the running MFW pump. Due to decreasing steam generator levels and an expected reactor trip, operators manually initiated both MDAFW pumps and the TDAFW pump to return SG levels to normal. The running MFW pump was manually tripped to

protect it from loss of NPSH. Concurrently, control rods were manually inserted to decrease reactor power to approximately 1% (mode 2). Due to the manual initiation of AFW, the licensee made a second 10 CFR 50.72 call to the NRC due to the consideration that the AFW initiation was a manual ESF actuation. Operator actions during these events are further discussed in paragraph 3.a.1.

The unit was maintained at approximately 1 % power (MODE 2) with the SGs being supplied by the two MDAFW pumps until repairs were completed to the transformer.

(3) On September 22, 1992, the licensee made a call to the NRC as required by 10 CFR 50.72 with regard to an offsite notification to the FAA due to cooling tower number 1 having an extinguished light.

Within the areas inspected, one unresolved item was identified.

4. Maintenance Inspections (62703)

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

a. The inspectors observed portions of the performance of PM054780017. This PM was used in conjunction with TS-65-17 to verify that the B-train EGTS temperature switch was within calibration limits. The inspectors reviewed the related documentation, which appeared to be complete and accurate. IM personnel were also cognizant of the PM requirement to verify temperature switch performance using a bath heatup rate of 1 degree Fahrenheit per minute. The temperature switch was found to satisfy acceptance criteria. The inspectors also witnessed the independent verification of the relanding of the electrical leads, and noted that the verifier did not travel with the IMs and was not assisted by the IMs on locating the equipment. The inspectors also verified that control room logs properly documented that the A-train EGTS was out-of-service, and TS 3.6.1.8 LCO was appropriately entered. The inspectors concluded the above PM was performed satisfactorily.

b. On September 18, the inspectors reviewed the licensee process for the installation of tags and labels on plant equipment. The licensee's Maintenance Program group had been performing these activities during the past week per SSP-6.56, LABELING AND IDENTIFICATION TAG REQUEST FORM PROGRAMS, Rev. 0. Section 10.8 of SSP-6.56 states that tags/labels will be installed by responsible plant personnel according to their expertise or job classification. For example, Operations personnel will install

tags/labels on equipment or components such as valves, fuses, pumps, etc. In addition, SSP-6.56 requires second party verification.

The inspectors held discussions with two individuals (an Auxiliary Unit Operator and a chemistry technician) in the Maintenance Program group. These individuals stated that approximately 125 tags/labels had been installed during the last week by the group on equipment located in the turbine building. The AUO stated that he has previously stood on-shift as turbine building AUO. Personnel in this group included the two individuals above, one electrician, and a laborer. The inspectors questioned the two individuals on the training qualifications needed to perform SSP-6.56. The chemistry technician stated that he would not feel comfortable hanging tags unless the AUO was present. Likewise, the AUO stated he did not feel comfortable with the process of using non-operations personnel to hang tags and labels, or the second party verification. The process of hanging tags involved the AUO as the second party verifier, and the other individuals as the primary installers of tags or labels. The AUO stated that on some occasions in which he did not feel comfortable with the location or identification of components to be tagged, he notified his manager. The manager then requested other groups with expertise in this type of equipment to hang these tags.

The inspectors also held discussions with the manager of the Maintenance Programs group, who indicated that he and the AUO had discussed with the other group personnel the requirements of SSP-6.56. The Maintenance Programs manager stated that the AUO, working in conjunction with the other individuals, satisfied the qualification requirements of SSP-6.56.

The licensee generated PER No. SQPER9220306 on September 22 associated with this issue. Specifically, the PER stated that SSP-6.56 was violated in that individuals were not qualified to hang tags on plant valves and equipment. The PER stated that the individuals were not familiar with the components or prints for the items in which they were hanging tags. Thus, this made the intent of the second party verification of proper placement invalid.

The inspectors concluded that there is reasonable assurance that the above tags and labels were installed correctly, based on discussions and knowledge level of the AUO. The licensee is currently reviewing this issue, and may provide additional information and corrective actions. Pending licensee and NRC completion of reviews, this issue will be identified as Unresolved Item URI 327, 328/92-30-02, Possible Installation of Tags/Labels Contrary to SSP-6.56.

c. On September 18, 1992 the inspectors reviewed activities associated with troubleshooting and repair of the Unit 2 main

steam line radiation monitor, 2-RI-90-423. The inspectors reviewed activities associated with preparation for work on the monitor, verified that appropriate operational control was in affect for work on the monitor, discussed the troubleshooting process with the technicians involved in the maintenance activity, and reviewed the completed work order package # 92-13148-00 after the monitor was repaired. The inspectors concluded that the troubleshooting/repair activity was accomplished in accordance with requirements.

d. On September 21, during review of the CR logs, the inspectors became aware of the identification of leakage from the Unit 1 RHR spray header 1-A inside the containment. The leakage was approximately one drip per two seconds out of a weephole located in a vertical section of the RHR spray line. The inspectors questioned system engineering as to the cause of leakage and were informed that the spray header isolation valve, 1-FCV-72-40, was suspected of leaking through and allowing a column of water to form to a level at least up to the weephole. No leakage was identified out of the spray header itself. The leakage through 1-FCV-72-40 appeared to be exacerbated by a continuing problem of pressurization of both of the RHR discharge piping trains. The RHR piping had been pressurizing to approximately 480 psig for several months according to operations personnel. Normal RHR discharge pressure with the pumps not running is less than 50 psig. The pressurization was previously brought to the attention of System Engineering by Operations and was evaluated as an abnormal condition; however, not affecting operation of the safety-related system.

Due to the recent identification of the 1-FCV-72-40 leakage, System Engineer involvement again was focused on the pressurization problem and an action plan was developed to troubleshoot the issue. The pressurization was suspect to originate from leakage through one or more cold leg accumulator check valves which are connected to the RHR discharge piping. The inspectors reviewed the licensee's actions with regard to the pressurization of the RHR discharge piping. The initial decision to operate with the abnormal condition until further evaluation of the phenomenon was based on no adverse affects on the operation of the RHR system. This decision appeared to the inspectors to be acceptable. However, the inspectors noted that an action plan was not initiated to troubleshoot the pressurization problem until it resulted in the additional issue of leakage through 1-FCV-72-40 into the containment several months later. The inspectors will continue to monitor the licensee's resolution of these issues during future inspections.

Within the areas inspected, one unresolved item was identified.

5. Surveillance Inspections (61726)

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. 2-SI-SFT-026-073.B, Fire Pump 2B-B Performance Test, Revision 0. The inspectors reviewed the results of the test which provided assurance that the fire pump would meet the TS required flow and pressure requirements. The procedure appeared to adequately control the activity and also provided adequate compensatory provisions if the fire protection system was called on for use during the test. The test director was qualified to perform the test. One test deficiency was identified during the performance of the procedure. The inspectors verified that the deficiency was adequately addressed, did not affect the results of the test, and was administratively controlled to assure proper resolution. Initial results of the test indicated that all of the acceptance criteria were met.

b. 2-PI-OPS-000-023.1, Modes 1-4 Control Room Operator MCR Duty Station Shift Relief and System Status Checklist, Revision 5. During the inspection period, the inspectors reviewed several performances of the PI. The PI is utilized as part of the shift turnover process. During the observations and reviews, the inspectors noted that the operations personnel completing the documentation were generally attentive in the accomplishment of the checklist and properly annotated abnormalities between the checklist requirements and control room indications being monitored. One minor discrepancy was identified in which operators over several shifts appeared to be logging CCS A and B Surge Tank Level values which were consistently above the nominal range values indicated in the PI. The inspector identified this to the shift ASOS who stated that he was aware of the issue, that the actual tank level values were previously evaluated as acceptable, and that a procedure change was in process which would include an adjustment to the nominal range value. The inspector verified the procedure change request for the PI and had no further concerns. However, the inspectors did note that operators were annotating as-found values which exceeded nominal range values without highlighting the abnormal values in the subject PI. The inspectors discussed this with operations management, who, upon review of this practice, decided to change the PI to require special highlighting of abnormal or unexpected values so that the indications would receive appropriate management review. The highlighting practice already existed in other operations logging procedures. The inspector concluded that the performances of the PI were adequate.

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.

a. The inspectors attended a PERP meeting on 9/15/92 for Incident Investigation No. II-S-92-068 Lack of Chemical Traffic Control. This issue was identified during a walkdown of the 690' elevation of the auxiliary building by visiting NRC inspectors, and is fully discussed in NRC Inspection Report No. 50-327,328/92-25. During the walkdown, unidentified/unapproved and unlabeled chemicals were found in lockers and gang boxes, contrary to the requirements of SSP-13.2, CHEMICAL TRAFFIC CONTROL (CTC) PROGRAM, Rev. 4. The licensee attributed the noncompliance to insufficient management enforcement and a lack of specialized craft training. The root causes and corrective actions for this event were fully discussed during the PERP. These activities will be reviewed by the NRC during future inspections.

b. The inspectors attended a PERP meeting on 9/16/92 for Incident Investigation No. II-S-92-071, Testing of the Incorrect Circuit Breaker. On September 3, 1992, during a routine review of a performance of SI-275.2, TESTING OF NON-CLASS 1E LOAD CIRCUIT BREAKERS FED FROM CLASS 1E BUSES, a discrepancy was noted in the type of breaker listed on one of the data sheets. Subsequent investigation revealed that the wrong breaker had been tested during the SI performance. The system engineer reviewing the SI package notified the SOS, and TS LCO 3.8.3.3.b was entered on September 8, 1992. The breakers, associated with ERCW building heaters, were removed from service and tested. Test results were satisfactory.

The licensee's II team identified that on November 1, 1990, during a change-out of breaker FL/4FL, a type FDB breaker was used to replace the existing type FB breaker. TS 4.8.3.3.a requires that 10% of each type of circuit breaker be functionally tested at least once per 18 months. On September 3, 1991 a preliminary sample population list containing 10% of the type FB breakers was issued for scheduling purposes, to be tested in accordance with SI-275.2 during the Unit 2 cycle 5 outage. On March 4, 1992 an official SI-275.2 package sample population list was generated, and included with the SI package.

The II team determined that the preliminary population list and the official population list were not the same lists. Six breakers were mis-identified. During the performance of SI-275.2, a foremen's outage work list (daily schedule) of breaker testing was used by the electrical foremen, and was generated from the outage schedule list using the preliminary breaker population of

September 3, 1991. The daily schedule identified that breaker FL/4FL was to be tested. However, the SI package contained the official population list of March 4, 1992, and identified breaker FL/4ER to be tested. The foreman should have used the official population list contained in the SI package to perform the surveillance. For the other five breakers that were mis-identified on the daily schedule, the foremen used official breaker list contained in the SI package. Thus, the correct breakers were properly tested.

Breaker FL/4FL was tested and SI-275.2 was completed on June 3, 1992. The system engineer, while performing a final technical review of the SI package, noticed that the craft personnel identified breaker FL/4ER as a type FDB breaker. The system engineer was cognizant of the fact was breaker FL/4ER was a type FB breaker, and not a type FDB breaker. The licensee identified that the maximum allowable extension on TS surveillances of 25% was exceeded on July 28, 1992.

The licensee's II team identified the root cause to be a failure to follow procedures associated with material procurement and issue. Procedures require that receipt of replacement material or equipment that is not a like-for-like replacement be properly qualified. The II team is still reviewing all procedures associated with material procurement and issue to determine the extent of this root cause. The licensee initiated a purchase request for six type FB breakers on in 1988. In November 1989, the request was revised, and recommended a part number change to purchase type FDB breakers. No request was made to evaluate the acceptability of the FDB type breakers, which were received by SQN power stores on December 1989. In November 1990, a type FDB breaker was installed as a like-for-like replacement for the type FB breaker during the change out of circuit breaker FL/4FL.

The II team identified that the computer program which generated the random population list of breakers to be tested during the outage has the potential for generating different lists. As such, the preliminary list generated on September 3, 1991 was different from the list generated on March 4, 1992. The preliminary list was used to schedule breaker testing, and was used to generate the foreman's outage work list. This list was different than the official population list, generated on March 4, 1992 contained in the SI-275.2 package.

The licensee will issue an LER for this event due to a missed TS surveillance. The inspectors will also identify this issue as inspector follow-up item IFI 327,328/92-30-03, Review of Incorrect ERCW Breaker Testing.

Within the areas inspected, no violations were 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 328/92-10, Residual Heat Removal Pump Inoperable due to a Miswired Flow Switch for the Miniflow Valve. During the performance of a surveillance instruction, the licensee identified that the RHR pump 2B-B miniflow valve was malfunctioning. The RHR pump was immediately declared inoperable and an investigation was begun to determine the cause. An incorrectly terminated wire on a flow switch was determined to have caused the valve to cycle continuously. The wire was subsequently reterminated and the equipment was appropriately tested and returned to service. Root causes for the problem included inadequately performed second-party verification and an inadequate post maintenance test for the maintenance activity. This event also resulted in a violation being identified in NRC Inspection Report 327, 328/92-22. The final corrective actions for the LER 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) VIO 327, 328/91-06-01, Failure to Follow the Requirements of AI-37, INDEPENDENT VERIFICATION. The violation involved a Unit 2, #3 cold leg accumulator breaker being left in the energized condition during plant operation. The breaker was manipulated during a non-routine evolution without the performance of any independent verification as required by AI-37, INDEPENDENT VERIFICATION. The evolution was being performed by the licensee to reduce known inleakage to the #3 cold leg accumulator. The evolution required the temporary closure of the isolation valve and breaker in an attempt to seat the leaking check valve for the accumulator. However, during breaker realignment, an operator mistakenly locked the breaker in the closed (energized) position. The licensee identified the cause of the violation as an incorrect decision to perform the activities involving the breaker as a limited evolution not requiring a procedure. Initial licensee actions to the issue included an operations night order to prevent any further limited evolutions prior to proper evaluation of the problem. Corrective actions included guidance being incorporated into associated procedures governing the conduct of limited evolutions and a training package highlighting the event was

provided to licensed personnel. The inspectors verified appropriate procedure changes were incorporated and concluded that the corrective actions taken by the licensee were adequate and that overall sensitivity to performing limited evolutions was heightened. In addition, the inspectors reviewed a current usage of a limited evolution as described in SSP-12.1, CONDUCT OF OPERATIONS, which involved the EDG starting air system. No additional concerns were identified. Other subsequent problems have been identified in the area of independent verification since the issuance of the violation. The inspector reviewed these problems in relation to the subject violation and concluded that the root causes for the more recent problems involving independent verification were not directly related to the violation and the corrective actions taken by the licensee. The inspectors will continue to monitor licensee corrective actions for the other problems identified in the area of component verification and post maintenance testing.

b. (Closed) VIO 327, 328/91-23-01, Failure to Maintain an Operable RHR Loop as Required by TS 3.9.8.1. The violation involved the inadvertent closure of the "A" train RHR pump suction valve because of the actuation of an interlock during performance of PM on the RHR pump suction valve from the containment sump. This action caused the operating RHR loop to become inoperable for approximately one minute with Unit 1 in a Mode 6 condition. The licensee identified two inappropriate actions associated with this event. The first was considered to be the failure to adequately address the implications of revising the schedule for the PM on the suction valve from the containment sump. The second is associated with the approval to perform the PM on the valve.

The inspectors reviewed the licensee's response to the violation, dated December 18, 1991, and verified the completion of the commitments as noted in the response. Some of these commitments included:

- A revision of the outage standard to proceduralize the requirements that have been implemented for review of logic changes that COULD OR WOULD affect the risk-analyzed outage schedule before changing the schedule.
- The PM instruction for valve 1-MVOP-63-72 was revised to add a caution that the valve is interlocked with 1-FCV-74-3, and to require the signature of Operations personnel indicating knowledge of the interlock.
- The licensee made analogous revisions of PM instructions for other Unit 1 and Unit 2 valves.
- The licensee reviewed the current practice for work on energized equipment against industry good practices, and concluded their practice was satisfactory.

The inspectors consider the licensee's actions in response to this violation were satisfactory.

c. (Closed) VIO 327, 328/92-02-01, Violation of TS 6.8.1 for Failure to Follow the Requirements of SSP 10.1. The issue involved numerous examples of improperly filed drawings, examples of uncontrolled drawings, and examples of improperly labeled drawings identified at controlled drawings stations in the Auxiliary, Turbine, and other buildings. The inspectors reviewed the licensee's response to the violation, dated March 19, 1992. The licensee's corrective actions included a reduction in the number of drawing locations and the assignment of specific responsibility for filing revised drawings to Document Control and Records Management. Licensee personnel in this organization were trained and are cognizant of their responsibility for maintaining up-to-date drawings. The licensee performed a confirmatory audit of satellite drawing locations on April 3, 1992, to insure these locations were kept up to date. The Site Quality group has also performed audits of control room and satellite locations. The audits found only minor discrepancies. On September 23, 1992 the inspectors conducted a review of drawings located in the auxiliary building and the turbine building. Sixteen drawings were chosen at random, and fifteen of the sixteen drawings were of the most recent revision number. One drawing was revised on September 17, 1992 and thus had not been updated at these locations. Discussion with Document Control and Records Management personnel indicated that this one drawing was scheduled to be filed. The inspectors concluded that the licensee's corrective actions in response to this violation were satisfactory.

d. (Closed) VIO 327/92-03-01, Failure to Follow Procedure 1-SI-OPS-000-002.0. The issue involved a failure of control room operators to compare reactor coolant system flow with the acceptance criteria contained in Technical Instruction TI-28. The inspectors reviewed the licensee's response to the violation, dated April 10, 1992. Corrective actions included a revision of Unit 1 and 2 control room log SIs to place the RCS flow acceptance criteria directly on the SI data sheet, instead of referencing to a Technical Instruction Curve Book. Each SOS discussed the expectation of procedural compliance with the operating crews. The licensee also reviewed other Operations, Technical Support, Maintenance, Chemistry, Security, and Modifications SIs to identify acceptance criteria contained in reference documents that may be re-located to SIs. Revisions to these procedures have been completed. The inspectors reviewed and verified the completion of the above commitments. This issue was also discussed in LER 327/92-06.

e. (Closed) VIO 327, 328/92-03-05, Failure to Follow the Requirements of SSP-12.53. The issue involved an untimely 10 CFR 50.59 evaluation of a disabled annunciator for the Unit 1 Narrow Range RiD Failure Loop 3 alarm. A timely 10 CFR 50.59 was not performed because of a lack of understanding of responsibilities of the Work Control shift managers. Corrective actions included the completion of a 10 CFR 50.59 evaluation, and a memo to Work

Control shift managers explaining their responsibilities relative to initiating and tracking safety evaluation reviews. In addition, 0-PI-OPS-301-001.0, ANNUNCIATOR ALARM AND/OR P-250 COMPUTER POINT DISABLEMENT, Rev. 3, was revised to clarify and streamline the annunciator disablement process. The procedure was revised such that if an alarm was declared to be a nuisance and a safety evaluation was required, then a 10 CFR 50.59 evaluation must be obtained or the alarm returned to service within 14 days of disablement. In addition, all annunciators that are monitoring operable TS or safety-related equipment shall require a 10 CFR 50.59 review prior to disabling the annunciator. The inspectors reviewed and verified the revision to the above procedure.

Within the areas inspected, no violations were identified.

9. Exit Interview

The inspection scope and results were summarized on September 30, 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.

Item Number	Description and Reference
URI 327, 328/92-30-01	Determination of licensee compliance with the Security Plan with respect to Protected Area Lighting Deficiencies (paragraph 3.e).
URI 327, 328/92-30-02	Possible Installation of Tags/labels Contrary to SSP-6.56 (paragraph 4.b).
IFI 327,328/92-30-03	Review of Incorrect ERCW Breaker Testing (paragraph 6.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

ASOS - Assistant Shift Operations Supervisor
AUO - Auxiliary Unit Operator
CCP - Centrifugal Charging Pump
CCS - Component Cooling System
CFR - Code of Federal Regulations
CR - Control Room

DRP	-	Division of Reactor Projects
EDG	-	Emergency Diesel Generator
EGTS	-	Emergency Gas Treatment System
ERCW	-	Essential Raw Cooling Water
ESF	-	Engineered Safety Feature
F	-	Fahrenheit
FAA	-	Federal Aviation Association
FCV	-	Flow Control Valve
FW	-	Feedwater
GPM	-	Gallons per Minute
IFI	-	Inspection Follow-up Item
II	-	Incident Investigation
IM	-	Instrument Maintenance
KV	-	Kilovolt
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
MCR	-	Main Control Room
MDAFW	-	Motor Driven Auxiliary Feed Water
MFW	-	Main Feedwater
NOUE	-	Notification of Unusual Event
NPSH	-	Net Positive Suction Head
NRC	-	Nuclear Regulatory Commission
PER	-	Problem Evaluation Report
PERP	-	Plant Evaluation Review Panel
PI	-	Periodic Instruction
PM	-	Preventive Maintenance
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RTD	-	Resistance Temperature Detector
RWP	-	Radiation Work Permit
SG	-	Steam Generator
SI	-	Surveillance Instruction
SOS	-	Shift Operating Supervisor
SQN	-	Sequoyah
SSP	-	Site Standard Practice
TI	-	Test Instruction
TS	-	Technical Specifications
URI	-	Unresolved Item
V	-	Volt
VIO	-	Violation
WR	-	Work Request