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August 13, 1999

EA 99-207

Tennessee Valley Authority
ATTN: Mr. J. A. Scalice
Chief Nuclear Officer and
Executive Vice President
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: NRC INTEGRATED INSPECTION REPORT NO. 50-327/99-04 AND 50-328/99-04

Dear Mr. Scalice:

On July 17, 1999, the NRC completed an inspection at your Sequoyah 1 & 2 reactor facilities. The enclosed report presents the results of this inspection. The results of the inspection were discussed on July 26 and again on August 9, 1999, with Mr. M. Bajestani and other members of your staff.

The inspection was an examination of activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. Within these areas the inspection consisted of a selective examination of procedures and representative records, observations of activities, and interviews with personnel. Because the Sequoyah facility is participating in the NRC's Power Reactor Oversight Pilot Plant Study, the evaluation of regulatory issues documented in this inspection report were evaluated and dispositioned in accordance with Appendix F: Interim Enforcement Policy for Use During the NRC Power Reactor Oversight Process Pilot Plant Study, of the NRC Enforcement Policy.

Based on the results of this inspection, one potentially safety significant issue was identified. On June 30, 1999, inadequate performance of the storm drain system caused water from a heavy rainfall to backup and flood the turbine building railroad bay where the 6.9kv unit boards were located, creating the potential for a loss of offsite power. Three findings were identified during the event review and are discussed in the enclosed inspection report. One of these issues is identified as an apparent violation for failure to incorporate the storm drain system into the Maintenance Rule program. This apparent violation is pending completion of a determination of significance for the flooding event, under the NRC Significance Determination Process (SDP). Another issue, involving corrective action from a previous flooding event, is unresolved, pending further NRC review. Upon completion of our review, we will inform you of our final significance determination of these issues and any associated enforcement action.

One apparent violation was identified associated with the implementation of procedural changes to leave three containment penetrations open during fuel movement. These procedure changes were implemented without prior Commission approval, as required by 10 CFR 50.59, and, in effect, resulted in a change to the technical specifications. As discussed in Appendix F of the NRC Enforcement Policy, violations at facilities participating in the pilot plant study that impact the NRC's ability for oversight of licensee activities, such as those involving 10 CFR 50.59

issues, are not evaluated by the SDP. Instead, these issues will be dispositioned in accordance with the current NRC Enforcement Policy. Therefore, the significance and characterization of this apparent violation is pending NRC review, and you will be contacted at a later date regarding the results of our deliberations.

The NRC also identified six additional issues of low safety significance that have, as appropriate, been entered into your corrective action program and are discussed in the summary of findings and in the body of the attached inspection report. Of the six issues, five were determined to involve violations of NRC requirements, but, because of their low safety significance, the violations are not cited. If you contest these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Sequoyah facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

Sincerely,

(Original signed by Paul E. Fredrickson)

Paul E. Fredrickson, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket Nos. 50-327, 50-328
License Nos. DPR-77, DPR-79

Enclosure: NRC Inspection Report

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-327, 50-328
License Nos:	DPR-77, DPR-79
Report No:	50-327/99-04, 50-328/99-04
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant, Units 1 & 2
Location:	Sequoyah Access Road Hamilton County, TN 37379
Dates:	June 1 through July 17, 1999
Inspectors:	M. Shannon, Senior Resident Inspector D. Starkey, Resident Inspector R. Telson, Resident Inspector G. Salyers, Emergency Preparedness Specialist J. Kreh, Radiation Protection Specialist E. Testa, Senior Radiation Protection Specialist D. Thompson, Physical Security Specialist
Approved by:	P. Fredrickson, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

Sequoyah Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-327/99-04, 50-328/99-04

The report covers a 7-week period of resident inspection and announced inspections by a regional emergency preparedness specialist, two radiation protection specialists and a physical security specialist.

Inspection findings were assessed according to potential risk significance, and were assigned colors of Green, White, Yellow, or Red, based on the NRC's Significance Determination Process (SDP). Those findings that impact the NRC's ability to oversee licensee activities cannot be evaluated for their direct effect on safety, and were not assigned a color. Green findings are indicative of issues that, while not necessarily desirable, represent little risk to safety. White findings would indicate issues with some increased risk to safety, and which may require additional NRC inspections. Yellow findings would be indicative of more serious issues with higher potential risk to safe performance and would require the NRC to take additional actions. Red findings represent an unacceptable loss of margin to safety and would result in the NRC taking significant actions that could include ordering the plant shut down. The findings, considered in total with other inspection findings and performance indicators, will be used to determine overall plant performance.

Cornerstone: Initiating Events

- Potential Safety Significance. The inspectors identified that on June 30, 1999, inadequate performance of the storm drain system caused water from a heavy rainfall to backup and flood the turbine building railroad bay where the 6.9kv unit boards were located, creating the potential for a loss of offsite power. Based on this event, three findings were identified:

  – An apparent violation for failure to incorporate the storm drain system into the Maintenance Rule program. (Section 1R01)

  – An unresolved item involving improper correction of identified deficiencies following a prior July 1994 rain storm that could have prevented the June 1999 event. (Section 1R01)

  – A deficient temporary modification to the storm drain system which contributed to the June 1999 flooding event. (Section 1R01)

Cornerstone: Mitigating Systems

- Green. A non-cited violation was identified for failure to ensure the accuracy of a fire protection electrical drawing which resulted in an inadequate surveillance instruction and the resultant failure to perform a surveillance requirement. Fire detectors in fire zones 174 and 175 were wired such that they would actuate the wrong suppression valves and thus no water would be supplied to room 734.0-A17 in the event of an actual fire. The mechanical flow diagram and the pre-fire plan were correct and available, if needed, in the control room and to the fire brigade to assist in locating the suppression valves for the purpose of manual actuation of the valves. A design change was completed which corrected the deficiency. (Section 1R05)

- Green. Unit 2 main steam isolation valves (MSIVs) failed to meet the stroke time acceptance criteria during ASME Section XI testing in Mode 5 due to mechanical binding of the valves as a result of temperature differences between the valve body and poppet. The MSIVs were required to be operable in Modes 1, 2 and 3 only. The condition of concern (main steam line break following a cooldown to less than 447°F) is a condition that would normally be the result of a rapid cooldown. The thermal binding of the MSIVs did not directly affect the operability of the MSIVs in Modes 1, 2 or 3. Any uncontrolled cooldown at power or in Mode 3 would be mitigated by the rapid closure of the MSIVs by a safety injection actuation, using the guidance in ES-0.1 (Reactor Trip Response) following a reactor trip, or using AOP S.05, Steam or Feedwater Line Break/Leak, for cooldowns that are not associated with a reactor trip, or cooldowns in Mode 3. (Section 1R09)

- Green. An additional example of a previous Maintenance Rule misinterpretation non-cited violation was identified. When the dropping resistor on the Unit 1 turbine driven auxiliary feedwater pump (TDAFW) failed for the second time on January 20, 1999, the licensee, through a misinterpretation of Maintenance Rule unreliability criteria, did not consider it to be a functional failure and therefore did not consider classification of the system as (a)(1) under the Maintenance Rule. Following a third failure in May 1999, the TDAFW was classified as (a)(1). The issue of proper classification of functional failures and (a)(1) classification of the TDAFW pump under the Maintenance Rule did not affect the operability of the auxiliary feedwater system. (Section 1R12)

- Green. A non-cited technical specification violation was identified for loss of containment closure during refueling. Three direct unmonitored paths, specifically through containment penetrations for ice blowing, ice condenser drains and steam generator sludge lancing equipment, existed from inside containment to outside the containment atmosphere while fuel movement was in progress. The probability of fuel damage during fuel movement and potential for any substantial off-site release were low. (Section 1R20)

- An apparent violation was identified associated with the implementation of procedural changes to leave three containment penetrations open during fuel movement. These procedure changes were implemented without prior Commission approval, as required by 10 CFR 50.59, and, in effect, resulted in a change to the technical specifications. The significance and characterization of this apparent violation are being evaluated in accordance with Appendix F of the NRC Enforcement Policy, and is pending additional NRC review. (Section 1R20)

- Green. A non-cited violation was identified for failure to meet the 18 month surveillance requirements of TS 4.5.2.g.1 for a safety injection hot leg throttle valve. An inadequate surveillance procedure had failed to verify that the mechanical stop of the valve was in its correct position following maintenance on the valve. The valve was subsequently found out of its required position. In addition, the inspectors determined that the licensee was also not correctly performing this surveillance for other emergency core cooling system valves. The improperly throttled injection throttle valve did not affect the operability of the safety injection system and the inadequate surveillance procedure did not result in loss of function of the safety injection systems. (Section 1R22)

Cornerstone: Emergency Preparedness

- Green. A non-cited violation was identified in that the licensee implemented an emergency action level (EAL) change that decreased the effectiveness of the Emergency Plan without application to and approval by the Commission as required by 10 CFR 50.54(q). Had an event occurred during which this EAL would have been called upon, the EAL may not have required a declaration of an Alert even when a significant transient was in progress with loss of most or all annunciators associated with safety systems for greater than 15 minutes. The EAL methodology was based upon a risk-significant planning standard; however, the improper change involved only 1 of approximately 35 EALs. (Section 1EP4)

Report Details

Summary of Plant Status

Unit 1 operated throughout the inspection period at 100 percent power. Unit 2 also operated throughout the period at 100 percent power.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigation Systems, Barrier Integrity

1R01 Adverse Weather Preparations

a. Inspection Scope

During plant status review, the inspectors noted a June 30, 1999, control room log entry, that documented that at 4:10 p.m., the plant had experienced a turbine building railroad bay (TBRB) flooding event from heavy rainfall due to inadequate drainage. In addition, the log entry noted that the non-vital 6.9kv unit boards were in danger of being flooded. Inspectors performed a detailed review of the June 1999 flooding event to determine the effectiveness and/or adequacy of adverse weather preparations, adequacy of a recent temporary plant modification of the bus duct cooling system, applicability of the storm drain system for scoping under the maintenance rule, and the adequacy of corrective actions following a similar event in 1994.

b. Observations and Findings

Brief Overview

The NRC staff evaluated that the flooding event had potential safety significance, but had not determined the specific response band at the conclusion of the inspection period. In addition, one apparent violation, one unresolved item and a finding were identified related to the flooding event:

– An apparent violation for failure to incorporate the storm drain system into the Maintenance Rule program.

– An unresolved item involving improper correction of identified deficiencies following a July 1994 rain storm that could have prevented the June 1999 event.

– A deficient temporary modification to the storm drain system which contributed to the June 1999 flooding event.

Subsequent to completing the Significance Determination Process (SDP) for the flooding event, the apparent violation and the finding will be collectively evaluated for risk significance commensurate with the significance of the event. The unresolved item will be also be evaluated, subsequent to its enforcement resolution, commensurate with the significance of the event.

Discussion

Flooding Event

On June 30, 1999, the storm drainage system was unable to accommodate the combined demands of a heavy rainfall (0.67 inches in 15 minutes) and the estimated 800 gpm discharge flow from a temporary plant modification which had routed the discharge of both units' main generator bus duct coolers to a storm drain at the entrance to the TBRB. Inadequate performance of the storm drain system caused water to backup and flood the TBRB where the 6.9kv unit boards were located. Open conduit penetrations in the base of the 6.9kv unit boards permitted water to drain through the TBRB floor dousing the 250vdc distribution and 480vac motor operated valve (MOV) boards on the next lower elevation. Water, approximately 1 inch deep at the base of the unit boards, came to within 3 to 4 inches of contacting energized 250vdc control circuitry and came within approximately 5 inches of contacting the 6.9kv board insulators. Although an alarm was received and dc grounds were reported, equipment remained functional and no trip, transient, or engineered safety feature (ESF) actuation occurred. Both units operated at 100% power throughout the event.

The licensee concluded that the storm drain system lacked redundancy in that only one drain line leads away from the catch basins at the entrance to the turbine building railroad bay and that the basins were at a low point of the storm drain system, with no surface path available to carry water away from the turbine building railroad bay. Therefore, the inspectors noted that because of the design, when the storm drain system capacity is exceeded, the system will overflow from the low point catch basins into the turbine building railroad bay. The inspectors noted that this in turn could adversely affect the 6.9kv unit boards and offsite power. The NRC staff evaluated this flooding event to have potential safety significance, but had not determined the specific response band for this finding at the conclusion of the inspection period.

A similar flooding event occurred on July 11, 1994, when heavy rainfall, about 1 inch in 15 minutes, caused the storm drainage system to backup and flood the TBRB, cable tunnels, electrical manholes, and other areas on site. Water intruded into the 6.9kv unit boards (about 2 inches deep) and poured through the conduits dousing the 250vdc distribution boards and the 1C 480 vac MOV distribution panels.

Additionally, an earlier related flooding event occurred in 1986, involving flooded cable manholes and hand holes. Corrective action tracking documents addressed actions for resolution of the condition. The flooding condition was determined to be a result of improper surface grading, ground water in-leakage, and failure to perform preventive maintenance on the storm drain system.

Failure to Scope the Storm Drain System Within the Maintenance Rule

Discussions with the licensee's Maintenance Rule specialist indicated that the licensee had not considered or evaluated the site storm drain system during the scoping phase of systems to be included under the Maintenance Rule. Although the 1994 flooding event fell within the Maintenance Rule plant level event review period, and had resulted in a power reduction greater than 20%, the event was not considered because it had been improperly classified as a planned power reduction. Based on the licensee's plant design and the documented flooding, the inspectors concluded that a failure of the storm drain system had the potential to cause a reactor trip and an ESF actuation and therefore should have been included within the scope of the Maintenance Rule.

10 CFR 50.65, Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Section (b)(2), requires licensees to include non-safety related structures, systems, or components whose failure could cause a reactor scram or result in an ESF actuation, within the scope of the maintenance rule. Contrary to the above, as of June 30, 1999, the licensee had not included the storm drain system within the scope of the Maintenance Rule which is a violation of this requirement. The violation is identified as apparent violation (AV) 50-327,328/99004-01, Failure to Include the Storm Drain System Within the Scope of the Maintenance Rule. This violation is in the licensee's corrective action program as PER 99-006863-000.

<u>Inadequate Past Corrective Action to Protect the 6.9kv Unit Boards</u>

As documented in NRC Inspection Report 50-327,328/94-18, the NRC expressed concern about the inability of the storm drain system to handle the amount of rain received. The licensee conducted an extensive year-long root cause investigation following the July 11, 1994, storm event and developed a number of corrective actions intended to prevent recurrence. However, an NRC review of this investigation identified a number of corrective actions that were not implemented. The status of the proposed corrective actions is as follows:

– The licensee considered a corrective action to seal the open conduit penetrations in the base of the 6.9kv unit boards. This was to prevent water from pouring on and into the 250vdc distribution boards, the 480 MOV boards, and the circulating water bearing lubrication water pumps, during a flooding event. This item was closed to a work order that was never completed. The licensee also considered a corrective action item to install a water diversion curb around the 6.9kv unit boards. However, this corrective action item was canceled based on a corrective action item to rework the hard drainage and rework the plant grades.

– On August 23, 1995, a licensee's evaluation documented that the design capacity of a section of the storm drain system piping was undersized for rainfalls which were anticipated within the lifetime of the plant and that the capacity of the storm drain system could be expected to be exceeded for predicted rainfall events exceeding a five year capacity. Corrective actions to replace the undersized piping of the storm drain system were canceled.

– Based on the review of the 1994 flooding event, the licensee concluded that the flow configuration of site drainage might not be in accordance with the original site design. Corrective actions to address the site flow configuration were canceled.

The licensee canceled the above corrective actions on January 6, 1999, citing "insufficient technical merit and/or inadequate economic benefit."

- Following the 1994 flooding event, the licensee identified interim corrective actions to have sand bags accessible by the railroad bay door until corrective actions were implemented to protect the 6.9kv unit boards. The interim corrective actions were not maintained in that no sand bags were accessible by the railroad bay door during the June 30, 1999, flooding event.

- Following the 1994 event, the licensee identified an adverse condition in that the storm drain system discharge was backed up with water for several hundred feet which could result in an estimated system capacity reduction of approximately 20% from the original design. Discussions with the civil engineering group identified that this deficient condition had not been evaluated and any potential corrections to the storm drain system design capacity calculations were not pursued.

Based on the discussion above, the inspectors concluded that the licensee had not taken adequate corrective actions to protect the 6.9kv unit boards and as a result to protect the plant from a loss of offsite power. Pending further NRC review of the safety-related functions potentially impacted by this inadequate corrective action, this issue is identified as unresolved item (URI) 50-327,328/99004-02, Inadequate Corrective Actions to Protect the 6.9kv Switchgear and 250 vdc Distribution Panels.

<u>Deficient Temporary Modification to the Storm Drain System</u>

The inspectors reviewed the temporary alteration change forms (TACF 2-99-006-024, Rev. 1, TACF 2-99-007-024, Rev. 1) completed in April 1999 to temporarily reroute the discharge from the Unit 1 and Unit 2 non-safety-related bus duct coolers to a storm drain. The safety assessment characterized external flooding impact as "N/A" based on an assessment that the storm drain piping was adequately sized to accommodate the additional flow and still meet its design function. However, as noted in the corrective action section above, this appeared to be an incorrect conclusion.

The inspectors concluded that the TACF conclusion, that the storm drain piping was adequately sized to handle the additional flow, was incorrect. The additional flow from the bus duct cooling systems substantially reduced the rain-handling capacity of the drain system which the licensee had already determined was unable to meet original design standards. The inspectors noted that the TACF contributed to the 1999 flooding event with only two-thirds of the rainfall intensity the licensee predicted, in 1994, to cause system failure.

1R02 <u>Change to Licensee Conditions and Safety Analysis Report</u>

a. <u>Inspection Scope</u>

The inspectors reviewed three safety evaluations associated with the containment closure technical specification (TS) requirements.

b. <u>Observations and Findings</u>

Findings identified during this inspection are documented in Section 1R20.

1R04 Equipment Alignment

a. Inspection Scope

The inspectors reviewed the equipment alignment of the 2B-B centrifugal charging pump, during a period that the 2A-A centrifugal charging pump was out of service for repairs.

b. Observations and Findings

There were no findings identified and documented during this inspection.

1R05 Fire Protection

.1 Design Drawing Error Results in an Extended Inoperable Fire Suppression System

a. Inspection Scope

During the plant status review, the inspectors noted an April 26, 1999, log entry concerning fire detection zones 174 and 175 being aligned to the wrong suppression valves. The inspectors reviewed the circumstances related to fire detection zones 174 and 175 misalignment.

b. Observations and Findings

A non-cited (NCV) violation was identified for a failure to control the accuracy of a plant drawing, related to the fire suppression capability in a mechanical equipment room.

SI-234.6, Functional Test of Fire Protection Report Required Detectors in Panels 0-L-613, -614, -615, -616, -617, -618, and 0-L-620, Appendix 3, which implemented the surveillance requirement of 4.7.11.2.c.1.a, was written using electrical drawing 1,2-45W626-4, which had contained incorrect information since October 18, 1977. Drawing 1,2-45W626-4 incorrectly indicated that fire zones 174 and 175, which protect Unit 2 mechanical equipment room 734.0-A17, were associated with suppression valves FSV-26-143 and 2065. Fire zones 174 and 175 were actually protected by suppression valves FSV-26-151 and 2066. The detectors in zones 174 and 175 were wired such that they would actuate the incorrect suppression valves (143 and 2065) and thus no water would be supplied to auxiliary building room 734.0-A17 in the event of an actual fire. The licensee determined that the design error was present in the initial plant design and was likely due to lack of coordination between electrical and mechanical design disciplines.

The inspector verified that the mechanical flow diagram and the pre-fire plan were correct and available, if needed, in the control room and to the fire brigade to assist in locating the suppression valves for the purpose of manual actuation of the valves. Subsequently, the licensee initiated a design change notice to reconfigure fire detection zones 174 and 175 to automatically operate valves FSV-26-151 and 2066.

The inspectors reviewed licensee Technical Operability Evaluation 2-99-026-3198, Rev. 0, reviewed the licensee's fire hazards analysis calculation, SQN-26-D054, and walked down mechanical equipment room 734.0-A17. Based on these actions, the inspectors determined that the evaluations and equipment conditions were satisfactory.

Since the fire protection SDP was not available, the inspectors discussed the significance of the failed suppression system with the Region II senior reactor analyst (SRA) and with an NRR fire protection specialist. Based on the draft SDP for fire protection, titled, Determining Potential Risk Significance of Fire Protection and Post-fire Safe Shutdown Inspection Findings Evaluation Guidance, dated July 7, 1999, the inspectors screened this issue out of the SDP in Phase 1 as a Green finding.

10 CFR 50, Appendix B, Criterion III, Design Control, requires, in part, that measures shall be established to assure that applicable regulatory requirements and design basis are correctly translated into specifications, drawings, procedures, and instructions. Failure to ensure the accuracy of design drawing 1,2-45W626-4, is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control and is being treated as an NCV, consistent with Appendix F of the NRC Enforcement Policy. This violation is identified as NCV 50-328/99004-03, Failure to Ensure Accuracy of a Fire Suppression System Design Drawing and is in the licensee's corrective action program as PER 99-003198-000.

.2 General Systems Walkdowns

a. Inspection Scope

In June, the inspectors toured the cable spreading room, auxiliary control room, emergency core cooling systems rooms, shutdown board rooms, and high pressure feed pump rooms. In July, the inspectors performed a detailed walkdown of fire area FAA-OS4 (Auxiliary Building 714 level).

b. Observations and Findings

There were no findings identified and documented during this inspection.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors reviewed flood protection measures applicable to the TBRB flooding event.

b. Observations and Findings

Findings identified during this inspection are documented in Section 1R01.

1R09 Inservice Testing of Pumps and Valves

.1 Unit 2 Main Steam Isolation Valves (MSIV) Fail to Meet Stroke Time Acceptance Criteria in Mode 5

a. Inspection Scope

During the plant status review, the inspectors noted a May 3, 1999, log entry concerning failure of the Unit 2 MSIVs to meet stroke time acceptance criteria. The inspectors reviewed the licensee's actions related to the failure of all four Unit 2 MSIVs to meet the stroke time acceptance criteria during Mode 5 testing.

b. Observations and Findings

On April 18, 1999, Sequoyah Unit 2 entered Mode 5, Cold Shutdown (reactor coolant system (RCS) temperature ≤200°F), in preparation for entering a refueling outage. The MSIVs were stroke timed and all four failed to meet the stroke time acceptance criteria of five seconds. While still in Mode 5, the valves were stroked several times, and the last valve passed the acceptance criteria on April 20, prior to any routine maintenance being performed. After maintenance was performed, the valves were successfully stroked and met the acceptance criteria again on May 9, 1999, in Mode 3 when the unit was at normal operating temperature and pressure.

The licensee postulated that the cause of failure of the MSIVs to meet the stroking acceptance criteria was mechanical binding of the valves as a result of temperature differences between the valve body and poppet. The inspectors, with assistance of Region II engineering inspectors, reviewed the licensee's evaluation and concluded that the licensee's conclusion was reasonable. The inspectors reviewed the licensee's operability evaluation, documented in PER 99-002966-000, which determined that the potential for thermal binding of the MSIVs would be limited to plant conditions where the plant was rapidly cooling down. The PER documentation noted that a heat up event would have the reverse thermal expansion effect on the valve body and would open up the clearances due to the valve body heating up faster than the piston. The PER evaluation concluded that thermal binding of the valve body and piston was only credible for temperature differences greater than 100°F during a cooldown, based on nominal design clearances established by the valve vendor. The PER evaluation concluded that the only scenario where thermal binding was possible in modes that required MSIVs to be operable (Modes 1, 2, and 3), was a rapid cooldown in Mode 3 from 547°F to 350°F. During this scenario, the licensee concluded that thermal binding did not become a possibility until the RCS had cooled down to ≤447°F. The licensee's evaluation concluded that thermal binding is not possible at stable RCS temperatures in Modes 1, 2, or 3, or during heatup at any rate in Mode 3. Because thermal binding of the MSIVs could occur following a rapid cooldown, the licensee concluded that it would be appropriate to stroke test the MSIVs following the next plant cooldown to 350°F.

The inspectors, with input from the Region II SRA, screened this issue out of the SDP in Phase 1 as a Green finding. Since the thermal binding of the MSIVs did not directly affect the operability of the MSIVs in Modes 1, 2 or 3, the inspectors concluded that the stroke time deficiencies did not constitute a violation.

.2 Other Inservice Testing of Pumps and Valves

a. Inspection Scope

The inspectors observed the inservice testing of the 1B-B RHR Pump surveillance instruction, 1-SI-SXP-074-201.B, Residual Heat Removal Pump 1B-B Section XI Testing

b. Observations and Findings

There were no findings identified and documented during this inspection.

1R10 Large Containment Isolation Valve Leak Rate & Status Verification

a. Inspection Scope

The inspectors reviewed Operations Surveillance 1(2)-SI-OPS-030-2860.0, Rev. 0, Cumulative Time That Containment Purge Supply and Exhaust Isolation Valves are Open.

b. Observations and Findings

There were no findings identified and documented during this inspection.

1R12 Maintenance Rule Implementation

.1 Unit 1 Turbine Driven Auxiliary Feedwater Pump (TDAFW) Maintenance Rule (a)(1) Status

a. Inspection Scope

During the plant status review, the inspectors noted a May 3, 1999, log entry concerning the failure of the Unit 1 TDAFW pump speed control circuitry. The inspectors reviewed the licensee's actions related to Maintenance Rule (a)(1) classification following the third failure of the Unit 1 TDAFW speed control power supply dropping resistor.

b. Observations and Findings

An additional example of an NCV was identified, related to a misinterpretation of Maintenance Rule unreliability criteria for the AFW system, resulting in a component failure not being considered as a functional failure. Therefore the system was not considered for classification as (a)(1) under the Maintenance Rule, 10 CFR 50.65, in January 1999.

The inspectors determined that when a dropping resistor on the Unit 1 TDAFW failed (non-demand failure) for the second time on January 20, 1999, the licensee did not consider the AFW system for classification as (a)(1) under the Maintenance Rule.

Following the third non-demand voltage dropping resistor failure on May 4, 1999, the Maintenance Rule Expert Panel, on May 20, 1999, placed the Unit 1 TDAFW in (a)(1) status. (The power supply to the turbine speed control circuit is through a dropping resistor which reduces voltage from 125 Vdc to 48 Vdc. When the dropping resistor fails, then the power supply fails which renders the TDAFW turbine inoperable).

The licensee's Maintenance Rule unreliability criteria for the TDAFW pump (0-TI-SXX-000-004.0, Attachment 3, Section 2.1, Revision 7) states: "The performance criteria for this system is established as no more than...1 failure per 24 demands for the TDAFW pump."

The Maintenance Rule Expert Panel found that the system engineer had concluded that three non-demand failures did not count against the unreliability criteria and therefore did not recognize that the system should have been considered for classification as (a)(1) following the second failure. The Maintenance Rule Expert Panel meeting on May 20, 1999, concluded that the unreliability criteria would include all functional failures and not just those that only occur during a demand on the system. The licensee was still investigating the root cause of the failures at the close of the inspection period.

The licensee initiated PER 99-003523-000, for tracking the (a)(1) status of the Unit 1 TDAFW pump and to present a plan that would return the equipment to (a)(2) status. Additionally, following discussions with the inspectors, PER 99-006861-000 was initiated to document that the dropping resistor failure was initially incorrectly classified under the Maintenance Rule by the system engineer. The licensee initiated an action item to reword the unreliability criteria for the TDAFW to clarify that all failures are to be counted, not just those related to demands.

Since the issue of proper classification of functional failures and (a)(1) classification of the TDAFW pump under the Maintenance Rule did not affect the operability of the auxiliary feedwater system, the inspectors, with input from the Region II SRA, screened this issue out of the SDP in Phase 1 as a Green finding.

The inspectors reviewed recent similar Maintenance Rule mis-classification issues documented in Inspection Report 50-327,328/99-03. The issues resulted in NCV 50-327,328/99-03-04. Licensee corrective actions for that NCV were documented in PER 99-001846-000. The inspector reviewed the corrective actions of PER 99-001846-000 and determined that the scope of those corrective actions, which were still being implemented, was applicable to the mis-classification issue related to the TDFAW and are appropriate to prevent recurrence. Therefore, this failure to classify the AFW system as (a)(1) under the Maintenance Rule in January 1999 is identified as an additional example of NCV 50-327,328/99-03-04.

.2 Scoping of Systems Under Maintenance Rule

a. Inspection Scope

The inspectors reviewed scoping of systems under the Maintenance Rule.

b. Observations and Findings

Findings identified during this inspection are documented in Section 1R01.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following operability evaluations:

- Improperly Throttled Safety Injection Loop 3 Hot Leg Throttle Valve (Section 1R22)
- Thermal Binding of Main Steam Isolation Valves (Section 1R09)
- Inoperable Fire Suppression System (Section 1R05)
- Storm Drains (Section 1R01)

b. Observations and Findings

Findings identified during this inspection are documented in the section listed.

1R16 Operator Workarounds

a. Inspection Scope

The inspectors reviewed the following workarounds:

- SQ96034WA, Reachrods
- SQ99002WA, Centrifugal Charging Pump - Vital Inverter Fluctuations

b. Observations and Findings

There were no findings identified and documented during this inspection.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors observed the following post maintenance testing:

- post maintenance testing following replacement of the normal feed breaker to the 6.9 kv shutdown board 1A.
- post maintenance testing on the 1A-A CCP following routine scheduled maintenance.

b. Observations and Findings

There were no findings identified and documented during this inspection.

1R20 Refueling and Outage Activities

a. Inspection Scope

During plant status review, the inspectors noted an April 29, 1999, control room log entry that stated that containment closure had been lost and that the licensee had suspended all core alterations. The inspectors noted, based on the licensee's documentation, that a direct unmonitored path from inside containment atmosphere to the auxiliary building roof (outside the containment atmosphere) existed when a temporary ice blowing piping coupling became disconnected. In that containment closure was required to be set during refueling, the inspectors performed a review of the plant conditions and system alignment that led to the loss of containment closure.

b. Observations and Findings

Brief Overview

The inspectors identified one non-cited violation, with three examples of violation of TS 3.9.4.c which requires that each penetration providing direct access from the containment atmosphere to the outside atmosphere shall be either closed by an isolation valve, blind flange or manual valve or be capable of being closed by an operable automatic containment ventilation isolation valve. In addition one apparent violation of 10 CFR 50.59 was identified involving changes to a surveillance instruction than were made without prior NRC approval.

Discussion

Failure to Maintain Containment Closure During Fuel Movement

On April 29, 1999, at 2:14 a.m., the licensee identified that ice blowing piping had become disconnected from a containment penetration, which resulted in a breach in containment closure. All fuel movement was stopped until the breach was repaired. Fuel movement was re-initiated at 2:59 a.m. following repair of the disconnected ice blowing piping.

During the follow-up of this event, the inspectors noted that the installed ice blowing containment penetration, as it existed prior to the disconnect event, did not meet the requirements of TS 3.9.4.c. The ice blowing containment penetration should have been closed with a blind flange or valve during core alterations or fuel movement. Further review identified two other penetrations that did not meet this TS requirement. Specifically containment penetrations used for the ice condenser melt drain system and for the steam generator (SG) sludge lancing equipment, should also have been closed with a blind flange or valve.

Based on the low probability of fuel damage during fuel movement and low potential for any substantial off-site release, the inspectors, with input from the Region II PRA specialist, screened these three issues out of the SDP in Phase 1 as a Green finding.

These issues are three violation examples of a failure to maintain containment closure during movement of irradiated fuel, as required by TS 3.9.4.c.1, and are collectively being treated as an NCV, consistent with Appendix F of the NRC Enforcement Policy. This violation is identified as NCV 50-328/99004-04, Failure to Meet TS Requirements for Containment Building Penetrations and is in the licensee's corrective action program as PER 99-007066-000.

The inspectors noted that the installation and operation of the ice blowing piping to the containment penetration and the use of SG sludge lancing equipment penetration were previously discussed in NRC IR 50-327,328/91-23. This IR indicated that, based on discussion between Region II and NRR, these two issues were not regulatory safety significant. However, IR 91-23 did not discuss the effect of these conditions on the containment closure TS, nor did it discuss the effect of creating a 10 CFR 50.59 issue with the procedure changes. A subsequent discussion with NRR, in July 1999, determined that the penetration examples discussed above did constitute a violation of TS 3.9.4.c.1.

Inappropriate 10 CFR 50.59 Change

During the review of the three TS containment penetration violation examples, discussed above, the inspectors noted that the licensee had revised surveillance instruction (SI) 2-SI-OPS-088-006.0, Containment Building Ventilation Isolation (18Month/100 Hours/7 Days), used to verify the containment closure requirements of TS surveillance 4.9.4. The original procedural requirements noted that the containment penetrations were operable if they were either capped or isolated with a manual isolation valve during fuel movement. Revision 8 of the procedure, dated October 5, 1997, documented in Section 6.3 (3), that three safety evaluations "had been performed and approved to configure the system for use during core alterations." This procedure step allowed the licensee to consider the open containment penetrations during fuel movement or core alterations, as acceptable, although contrary to TS 3.9.4 requirements. In addition, the inspectors noted that prior to the October 5, 1997, revision to the SI, the licensee was using the deficiency notice (DN) process in order to keep the containment penetrations open during fuel movement or core alterations. Acceptability of the DNs on the open penetrations was tied to the three safety evaluations noted above, which had been initiated in 1991.

10 CFR 50.59 states that the licensee may make changes to the facility and procedures as described in the safety analysis report (FSAR), without prior Commission approval, unless the proposed change involves a change in the TS. FSAR Section 15.5.1.2.5, Fuel Handling Instructions, states, in part, that fuel handling instructions are used to ensure safe and orderly refueling operations and that these instructions make reference to other system operations documents that specify precautionary steps to assure that the technical specifications are not violated. Changes were made to SI 2-SI-OPS-088-006.0, a fuel handling instruction, without prior Commission approval, that involved a change to the technical specifications, by using the DN process and subsequently a procedural change, both of which did not meet the TS 3.9.4 requirements. The change to the facility and procedures as described in the safety analysis report, without prior Commission approval, that resulted in a change to the technical specifications is considered to be a violation of 10 CFR 50.59 requirements, and is identified as apparent violation AV 50-328/99004-05, Failure to Meet 10 CFR 50.59 Requirements. This apparent violation is in the licensee's corrective action program as PER 99-007066-000. Violations that may impact the NRC's ability for oversight of licensee activities, such as failures to obtain NRC approvals, are not evaluated by the SDP. As such, an SDP was not conducted for this finding which involves the failure to obtain NRC approval of

changes under the requirements of 10 CFR 50.59. The significance and characterization of this apparent violation is pending NRC review.

1R22 Surveillance Testing

a. Inspection Scope

During plant status review, the inspectors noted an April 24, 1999, control room log entry that stated that during testing the licensee was not able to meet the acceptance criteria for safety injection flow to the Unit 2 loop 1 hot leg and loop 3 hot leg. Based on this potential surveillance issue, the safety injection hot leg TS surveillance was selected for review during the June 1999 baseline inspection.

b. Observations and Findings

Brief Overview

An NCV was identified for failure to meet the 18 month surveillance requirements for TS 4.5.2.g.1. The licensee was not correctly performing the surveillance in that the surveillance procedure was not verifying the correct position of each "mechanical stop" for the charging pump injection throttle valves, the safety injection cold leg throttle valves, and the other safety injection hot leg throttle valves.

Discussion

The licensee had failed to adequately verify the correct position of safety injection hot leg throttle valve 2-63-444 since 1996. The valve was subsequently found out of its required position on April 24, 1999. Following discovery of the mispositioned safety injection hot leg throttle valve, the licensee initiated PER 99-003074-000. The licensee's associated operability evaluation stated that the safety injection system had still met the minimum flow requirements of 300 gallons per minute and had remained operable. The licencee's investigation found that the loop 1 hot leg throttle valve had been mispositioned following maintenance three years earlier. The inspectors reviewed the licensee's operability determination and found it to be adequate.

The licensee determined that following valve packing replacement on May 25, 1996, the post maintenance testing was deficient on safety injection hot leg injection throttle valve 2-63-544 and had not required system flow testing or valve positioning following the maintenance activity.

The licensee also concluded that, although valve 2-63-544 was mispositioned, the TS requirements to verify the correct position of the mechanical stop had been met. TS surveillance 4.5.2.g requires the licensee to verify the correct position of the mechanical stops for the subject emergency core cooling system (ECCS) throttle valves (1) within four hours following completion of maintenance on the valve (when the ECCS subsystems are required to be operable) and (2) at least once per 18 months. ECCS safety injection hot leg throttle valve 2-63-544 is covered by TS 4.5.2.g. The TS surveillance required by TS 4.5.2.g was performed on May 28, 1996, and again on

October 13, 1997; however, performance of the TS surveillance did not identify the mispositioned valve.

Subsequently, the inspectors questioned the licensee's conclusion. The inspectors reviewed SI 0-SI-OPS-063-212.0, ECCS Throttle Valve Mechanical Stop Position, Revision 1. This surveillance procedure was used to meet the requirements for surveillance testing per TS 4.5.2.g. Section 6.0 of the procedure requires the operator to "verify the stem lock installed and appears to be tightened firmly against the yoke bushing." The surveillance procedure did not verify that the mechanical stop was in its correct position as required by surveillance requirement TS 4.5.2.g. Therefore, the inspectors concluded that TS 4.5.2.g. had not been met and that the SI had contributed to the licensee not meeting the surveillance requirements of TS 4.5.2.g. The inspectors also determined that SI 0-SI-OPS-063-212.0 had also not been verifying the correct position of each "mechanical stop" for the charging pump injection throttle valves, the safety injection cold leg throttle valves, and the other safety injection hot leg throttle valves.

Since the improperly throttled safety injection system hot leg injection throttle valve did not affect the operability of the safety injection system and the inadequate surveillance procedure did not result in loss of function of the safety injection or high head safety injection systems, the inspectors, with input from the Region II SRA, screened this issue out of the SDP in Phase 1 as a Green finding.

The failure to properly conduct surveillance testing in accordance with TS 4.5.2.g. is considered a violation and is being treated as an NCV, consistent with Appendix F of the NRC Enforcement Policy. This violation is identified as NCV 50-327,328/99004-06, Failure to Meet TS Surveillance Requirements for Position Verification of Emergency Core Cooling System Throttle Valve Position and is in the licensee's corrective action program as PER 99-003074-000.

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1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed temporary alteration change (TACF) for rerouting of bus duct cooling water.

b. Observations and Findings

Findings identified during this inspection are documented in Section 1R01.

Cornerstone: Emergency Preparedness

1EP1 Drill and Exercise Inspection

(Closed) Inspection Follow-up Item (IFI) 327, 328/98-14-01: Untimely State Notification During Biennial EP Exercise. The inspectors determined that the issue had been entered into the licensee's corrective action program. This item is administratively closed.

1EP2 Alert and Notification System

a. Inspection Scope

The inspectors evaluated the alert and notification system (ANS) testing program for compliance with commitments, reviewed modifications to the ANS and its testing program, and reviewed the licensee's problem identification and resolution program for the ANS.

b. Observations and Findings

On June 2, 1999, two of 108 sirens comprising the ANS, failed the monthly full-cycle test. As of June 17, 1999, one the two sirens (siren no. 105) was still inoperable. Prompt repair could have been conducted, but was not.

The inspectors determined that siren no. 105 was still inoperable following its monthly full-cycle test on June 2, 1999. Repair records indicated that field testing on June 2 identified an apparent failure of the chopper motor, and the motor was scheduled for replacement. However, the special "bucket" truck required for this task was in use at the Watts Bar Nuclear Plant. Interviews with cognizant maintenance personnel disclosed that a suitable vehicle could have been procured to effect the needed repairs, but was not. The inspectors did not identify any specific regulatory or procedural requirements applicable to this situation. However, licensee management agreed that its expectations of prompt repair of identified siren problems had not been met in this instance. The licensee also indicated that follow-up of this issue would include review of the corrective action system for tracking siren problems to determine whether improvements were needed.

1EP3 Emergency Response Organization Augmentation

a. Inspection Scope

The inspectors reviewed the design of the emergency response organization augmentation system and the maintenance of the licensee's capability to staff emergency response facilities within stated timeliness goals.

b. Observations and Findings

There were no findings identified and documented during this inspection.

1EP4 Emergency Action Level Changes

a. Inspection Scope

The inspectors reviewed changes to the emergency action levels (EALs) to determine whether any of the changes decreased the effectiveness of the Emergency Plan.

b. Observations and Findings

Brief overview

The inspectors reviewed Revisions 40, 43, and 45 of TVA's Radiological Emergency Plan which involved EAL changes specific to Sequoyah. An NCV was identified for decreasing the effectiveness of the Plan as a result of a nonconservative change to an EAL.

Discussion

Nonconservative Change to an EAL

The inspectors reviewed Revision 40 to TVA's Radiological Emergency Plan. Revision 40 involved changes to the Notification of Unusual Event (NOUE) and Alert EALs for Event 2.1, Loss of Instrumentation.

Plan Revision 23, dated August 14, 1995, incorporated the NRC-approved EAL scheme formulated in accordance with NUMARC/NESP-007, Methodology for Development of Emergency Action Levels. Sequoyah's NUMARC EALs mirrored those of the licensee's Watts Bar Nuclear Plant, approved earlier by the NRC. The Revision 23 version of the Alert EAL for Event 2.1 regarding Loss of Instrumentation stated the following three conditions:

1. UNPLANNED loss of >75% MCR annunciators and annunciator printer [emphasis added] for >15 minutes or >75% of safety system indicators for >15 minutes.

   AND

2. SOS/SED judgement that increased surveillance is required (beyond shift compliment [*sic*]) to safely operate the unit.

   AND

3. (a or b)
   a. A significant plant transient is in progress.

      OR

   b. Loss of P-250 computer and SPDS [Safety Parameter Display System].

In Revision 40 of the above EAL, the licensee added the following three new peripheral indicators to Condition 1: (1) ICS MCR operator display station, (2) ADDS terminal, and (3) Annunciator operator display station.

The licensee's Alert EAL 2.1 was based upon NUMARC/NESP-007 Alert EAL SA4, "Unplanned Loss of Most or All Safety System Annunciation or Indication in Control Room..." One of the four conditions specified in the "template" for this EAL, (Condition d), specifies:

d. Either of the following: (1 or 2)
   1. A significant plant transient is in progress.

      OR

   2. *Compensatory non-alarming indications are unavailable.*[italics added for emphasis]

The inspectors reviewed the NUMARC/NESP-007 basis for Condition d, which states that compensatory non-alarming indications included both computer-based information such as the SPDS and all available computer systems.

The inspectors observed the location and data displayed on the three added peripherals in the control room, and determined that all three were *compensatory non-alarming indications*. The addition in Revision 40 of the three peripheral indicators to Condition 1 of Alert EAL 2.1 was not in accordance with the NUMARC/NESP-007 template, Condition d, because these compensatory non-alarming indications should properly have been included in Condition 3.b (part of an "or" statement). As changed in Revision 40, this EAL does not require declaration of an Alert when a significant transient is in progress with loss of most or all annunciators associated with safety systems for greater than 15 minutes, as long as any of the specified compensatory non-alarming indications are available. This result is at variance with the intent of the applicable NUMARC/NESP-007 template. The inspectors determined that adding the three peripherals to Condition 1 of Alert EAL 2.1 decreased the effectiveness of the approved Emergency Plan. The inspectors noted that the EAL methodology was based upon a risk-significant planning standard; however, the improper change involved only 1 of approximately 35 EALs. The licensee acknowledged that the addition of the three peripherals had decreased the effectiveness of the subject EAL and entered the finding into its corrective action system. The inspectors screened this finding out of the SDP in Phase 1 as a Green finding.

10 CFR 50.54(q), Conditions of licenses, states that the licensee may make changes to its emergency plan without Commission approval only if the changes do not decrease the effectiveness of the plan. The addition of the three peripherals in Revision 40 to Alert EAL 2.1, Loss of Instrumentation, constitutes a decrease in the effectiveness of the Radiological Emergency Plan, is identified as a violation of 10 CFR 50.54(q) and is being treated as an NCV, consistent with Appendix F of the NRC Enforcement Policy . This violation is identified as NCV 50-327,328/99004-07, Failure to Meet 10 CFR 50.54(q) Change Requirements Which Resulted in a Decrease of Emergency Plan Effectiveness and is in the licensee's corrective action program as PER No. 99-006622.

Peripheral Training Deficiencies

The inspectors asked a shift manager (SM) in the control room to point out the three new peripherals. The SM was unable to independently locate the ADDS terminal. Additionally, the SM and an SRO did not know how to operate the ADDS control console. Furthermore, the SM incorrectly identified the center console computer terminal as the "Annunciator operator display station." The inspectors interviewed a second SM, and he also failed to independently locate the ADDS terminal. The two SMs, an SRO and an STA also could not identify which control board alarms or indications were associated with safety systems. Although a separate issue, the inspectors also identified that an SM had difficulty using Emergency Operating Procedure FR-0, Critical Safety Function Monitoring. These training deficiencies had not resulted in an improper drill or event response and the licensee management stated that they planned to address these issues through the corrective action program.

EAL Inconsistency

From the initial NRC-approved Revision 23 through the current Revision 45 of the licensee's NUMARC/NESP-007 EAL methodology, the Site Area Emergency EAL for Event 2.1, Loss of Instrumentation, specified an "UNPLANNED [emphasis added] loss of >75% of safety system indicators or >75% of MCR annunciators." The inspectors noted the use of "UNPLANNED" was inconsistent with the NUMARC/NESP-007 Site Area Emergency EAL SS6 example and its basis, which states, in part "Loss of most or all annunciators associated with safety systems" and does not address "UNPLANNED" as a condition. This EAL would not consider events when, collectively, both planned an unplanned indicators exceeded the criteria. This inconsistency did not result in an improper drill or event response and the licensee initiated an EAL change to remove the word "UNPLANNED" from the referenced EAL.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control

.1 Personnel Exposure Records Reconciliation Project

a. Inspection Scope

The inspectors visited the licensee's corporate office to review the status of the Personnel Exposure Records Reconciliation Project, which was initiated in May 1994 to resolve observed inconsistencies in computer generated personnel exposure reports. The inspectors also reviewed the Project to determine whether identified problems were corrected appropriately. Those activities were evaluated for consistency with the requirements for radiation exposure related records and reports specified in Subparts L and M of 10 CFR 20.

b. Observations and Findings

There were no findings identified and documented during this inspection.

.2 Access Control For Radiological Controlled Areas

a. Inspection Scope

The inspectors reviewed the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas, and worker adherence to these controls.

b. Observations and Findings

There were no findings identified and documented during this inspection.

20S3 Radiation Monitoring Instrumentation

a. Inspection Scope

The inspectors reviewed the accuracy and operability of portable radiation instruments.

b. Observations and Findings

There were no findings identified and documented during this inspection.

3. SAFEGUARDS

Cornerstone: Physical Safety

3PP1 Access Authorization

a. Inspection Scope

The inspector interviewed representatives of licensee management and escort personnel concerning their understanding of the behavior observation portion of the personnel screening and fitness for duty program. In interviewing these personnel the inspector reviewed the effectiveness of their training and abilities to recognize aberrant behavioral traits.

b. Observations and Findings

There were no findings identified and documented during this inspection.

3PP2 Access Control

a. Inspection Scope

The inspector observed access control activities on July 13 and 14, 1999, and the seven-day equipment testing on July 14, 1999. In observing the access control activities the inspector assessed whether officers could detect contraband before it was introduced into the protected area.

b. Observations and Findings

There were no findings identified and documented during this inspection.

4. OTHER ACTIVITIES

4OA2 Performance Indicator Verification

a. Inspection Scope:

The inspectors evaluated the Unit 1 and Unit 2 RCS Specific Activity performance indicator (PI) by reviewing the primary system sample results for RCS activity.

b. Observations and Findings:

Following Unit 2 restart from the May 1999 refueling outage, RCS activity increased to approximately 31% of the TS limit, indicating potential fuel cladding defects in the reloaded core. After the initial few weeks, the RCS specific activity slowly decreased. The inspectors continued to monitor the RCS specific activity results during the inspection period for both units in order to confirm the RCS Specific Activity performance indicator. The RCS specific activity PIs, submitted on July 14, 1999, reflected the highest RCS Specific Activities (Unit 1 and Unit 2) for the month of June. The PI performance rating remained in the licensee response band.

4OA5 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on July 26, 1999 and again on August 9, 1999. The licensee acknowledged the findings presented.
The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

<u>Licensee</u>

M. Bajestani, Site Vice President
H. Butterworth, Operations Manager
R. Driscoll, Site Training Manager
M. Fletcher, Contractor Supervisor
E. Freeman, Maintenance and Modifications Manager
J. Gates, Site Support Manager
C. Kent, Radcon/Chemistry Manager
R. Kitts, Emergency Preparedness Manager (Corporate)
D. Koehl, Plant Manager
M. Lorek, Site Engineering Manager
M. Munroe, Emergency Preparedness Manager (Site)
B. O'Brien, Maintenance Manager
P. Salas, Manager of Licensing and Industry Affairs
J. Setliff, Manager of Security
J. Valente, Engineering & Support Services Manager
J. Wilkes, Operations Superintendent

<u>NRC</u>

R. Bernhard, Region II (RII)
R. Schin, RII
R. Hernon, Office of Nuclear Reactor Regulation (NRR)
M. Weston, NRR
R. Gibbs, RII
R. Correia, NRR
J. Colaccino, NRR
P. Madden, NRR
G. Wiseman, RII
K. Landis, RII

ITEMS OPENED AND CLOSED

<u>Opened</u>

327,328/99004-01	AV	Failure to Include the Storm Drain System Within the Scope of the Maintenance Rule (Section 1R01).
327,328/99004-02	URI	Inadequate Corrective Actions to Protect the 6.9kv Switchgear and 250 vdc Distribution Panels (Section 1R01).
328/99004-05	AV	Failure to Meet 10 CFR 50.59 Requirements (Section 1R20).

<u>Opened and Closed</u>

327,328/99004-03	NCV	Failure to Ensure Accuracy of a Fire Suppression System Design Drawing (Section 1R05).

328/99004-04	NCV	Failure to Meet TS Requirements for Containment Building Penetrations (Section 1R20).
327,328/99004-06	NCV	Failure to Meet TS Surveillance Requirements for Position Verification of Emergency Core Cooling System Throttle Valve Position (Section 1R22).
327,328/99004-07	NCV	Failure to Meet 10CFR 50.54(q) Change Requirements Which Resulted in a Decrease of Emergency Plan Effectiveness (Section 1EP4).
327,328/99-03-04	NCV	An Additional NCV Example of Maintenance Rule Mis-Classification (Section 1R12)

<u>Closed</u>

327,328/98-14-01	IFI	Untimely State Notification During Biennial EP Exercise (Section 1EP1).