U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-327, 50-328
License Nos:	DPR-77, DPR-79
Report No:	50-327/98-11, 50-328/98-11
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant, Units 1 & 2
Location:	Sequoyah Access Road Hamilton County, TN 37379
Dates:	November 22, 1998 through January 2, 1999
Inspectors:	M. Shannon, Senior Resident Inspector D. Starkey, Acting Senior Resident Inspector R. Telson, Resident Inspector R. Gibbs, Reactor Inspector (Section M8.1) K. VanDoorn, Senior Resident Inspector, Watts Bar (Section E3.1)
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Enclosure 2

EXECUTIVE SUMMARY

Sequoyah Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-327/98-11, 50-328/98-11

This integrated inspection included aspects of licensee operations, maintenance and engineering. The report covers a 6-week period of resident inspection, inspection by a region based inspector, and inspection by a senior resident inspector from another site.

Operations

- Assistant Unit Operators performed their routine rounds in a thorough and professional manner (Section O1.2).

- One violation was identified for failure to enter Technical Specification (TS) 3.0.3 when the limiting condition for operation for TS 3.3.1.1, Table 3.3-1, Functional Unit 13, Loss of Flow-Single Loop was not met (Section O1.3).

- With respect to the TS 3.0.3 violation, the licensee incorrectly entered TS 4.0.3 when the Surveillance Requirements requirements of TS 4.3.1.1.1 could not be performed (Section O1.3).

- With respect to the TS 3.0.3 violation, licensee management did not provide sufficient guidance to operators concerning performance of channel checks on Reactor Coolant System (RCS) loop flow instrumentation when it was known that the Loop 1 instruments were reading high on scale or bouncing above the top of scale (Section O1.3).

- With respect to the TS 3.0.3 violation, operators did not challenge the fact that Unit 1 Loop 1 RCS flow indicators had been drifting high making a valid channel check difficult to perform when the three indicators routinely indicated greater than 110%, the top of the calibrated instrument scale (Section O1.3).

- Based upon a detailed walkdown of accessible portions of Unit 1 Train A Safety Injection System, the inspectors concluded that the system was operable and being maintained in an acceptable material condition (Section O2.1).

- One violation was identified with two examples of failure to follow Emergency Operating Procedure ES-0.1 when operators failed to control RCS temperature and pressure following a Unit 1 reactor trip (Section O4.1).

- A non-cited violation was identified for failure to provide an adequate abnormal operating procedure (AOP-P.03), contributing to the failure to control RCS temperature and pressure following a reactor trip (Section O4.1).

Maintenance

- The licensee successfully implemented a design change to replace the batteries on all Emergency Diesel Generators (Section M2.1).

- The licensee made significant improvements in the breaker testing and maintenance program from April - December 1998 (Section M8.1).

- Until all the breakers in the plant have been inspected and tested to the new breaker program requirements, their reliability and affect on plant performance remains a concern (Section M8.1).

Engineering

- Ice Condenser modifications were properly evaluated for conformance to the Updated Final Safety Analysis Report (UFSAR) description of the system and required changes to the UFSAR were implemented. The licensee appropriately initiated changes to the UFSAR where clarifications were needed based on self-assessments and recent analyses (Section E3.1).

Report Details

Summary of Plant Status

Unit 1 operated throughout the inspection period at 100% power.

Unit 2 operated throughout the inspection period at 100% power.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was considered to be satisfactory.

O1.2 Assistant Unit Operators (AUOs) on Rounds

a. Inspection Scope (71707)

The inspector accompanied AUOs during performance of their rounds in the Unit 1 and 2 auxiliary buildings and the Unit 1 turbine building.

b. Observations and Findings

The inspector specifically observed the AUOs for thoroughness in performing rounds and utilization of the hand held electronic log recorder. The inspector noted that the data taken during AUO rounds had recently been reduced to eliminate unnecessary data taking and to record only data that was essential for trending purposes.

c. Conclusions

AUOs were observed to perform their routine rounds in a thorough and professional manner.

O1.3 Failure to Enter Technical Specification (TS) 3.0.3 for Inoperable Unit 1 RCS Loop 1 Flow Instruments

a. Inspection Scope (71707)

The inspector reviewed the licensee's actions related to failure of Unit 1 RCS loop 1 flow indicators (Unresolved Item 50-327/98-10-02).

b. Observations and Findings

On November 20, 1998, at 5:49 a.m., Unit 1 operators observed that RCS Loop 1 flow indicators 1-FI-68-6A, 6B, & 6D were "pegged off scale high." Surveillance Requirement (SR) 4. 3.1.1.1, Reactor Trip System Instrumentation, required that a

channel check be performed on the instruments once every shift (every 12 hours). SR 4.2.5.1, Departure from Nucleate Boiling (DNB) Parameters, required a verification of RCS total flow rate once every 12 hours. (Operators used the RCS loop flow indicators to perform the total flow rate verification). The channel checks were performed in accordance with 1-SI-OPS-000-002.0, Shift Log, Revision 41. The three flow indicating channels on each RCS loop were compared to each other with the channel check determined to be acceptable if the deviation between channels was equal to or less than 6%. The last channel check and RCS total flow verification had been performed on November 19, 1998, at 10:00 p.m., with the next surveillances due by 10:00 a.m. on November 20. The channel check consisted of comparing the three flow indicators on Loop 1 to verify they were reading within 6% of each other. The RCS total flow verification consisted of summing all four loop flows and averaging the sum of the flows.

At 1:00 p.m. on November 20 when the surveillances could not be performed within the 125% surveillance period interval, the licensee entered TS 4.0.3, which they believed granted an additional 24 hours because of the inability to perform the SR. At 6:20 p.m. on November 20, after reviewing data from the plant integrated computer (SG feed flow, RCS temperature, RCS leak rate, RCS pressure, and RCS Loop 1 flow) and confirming that no changes in the actual plant parameters had occurred, the licensee concluded that the Loop 1 flow transmitters were inoperable and entered TS 3.0.3. The licensee subsequently entered containment and tightened closed a leaking instrument line vent valve which restored the inoperable flow transmitters to operable status.

TS 3.3.1.1, Table 3.3-1, Functional Unit 12, Loss of Flow-Single Loop, requires two RCS flow channels per loop to be operable. On November 20, at 5:49 a.m. when all three channels of Unit 1 RCS Loop flow pegged off-scale high, the licensee was unable to perform the TS required channel checks nor were they able to determine Loop 1 RCS flow. Although the instruments had pegged off-scale high, the licensee failed to declare Loop 1 RCS flow instrumentation inoperable. Since the licensee did not declare the instruments inoperable, they likewise did not enter TS 3.0.3 when the LCO for TS 3.3.1.1 was not met at 1:00 p.m. on November 20. The failure to enter TS 3.0.3 when the LCO for TS 3.3.1.1 was not met is identified as a violation (VIO 50-327/98-11-01).

The inspectors determined that the licensee incorrectly entered TS 4.0.3 when TS SR 4. 3.1.1.1 could not be performed. The inability to perform a surveillance is not a valid reason for entering TS 4.0.3. The purpose of TS 4.0.3 is to provide an adequate time limit to complete SRs that have not been performed (missed surveillance). The 24-hour allowance of TS 4.0.3 is intended to permit the completion of a surveillance before a shutdown is required by TS ACTION requirements.

On January 8, 1999, Operations issued Standing Order 99-01 which summarized the inappropriate use of TS 4.0.3 on November 20. The Standing Order clarified to operators that TS 4.0.3 was intended to permit adequate time to complete an inadvertently missed surveillance and does not apply to a surveillance which cannot be performed due to inoperable components or instruments.

The inspectors concluded that licensed operators and licensee management were aware that the Unit 1 Loop 1 RCS flow instruments had been indicating high on-scale or bouncing above the top of scale for a period of at least six weeks following the Unit 1 refueling outage. However, neither operators nor management took action to have the RCS flow instruments rescaled or to provide procedural guidance in 1-SI-OPS-000-002.0 on how to perform the RCS loop flow channel checks during the time when the three indicators routinely indicated greater than 110%, the top of the calibrated instrument scale.

c. Conclusions

One violation was identified for failure to enter TS 3.0.3 when the licensee did not meet the limiting condition for operation (LCO) for TS 3.3.1.1, Table 3.3-1, Functional Unit 13, Loss of Flow -Single Loop. The licensee incorrectly entered TS 4.0.3 when the TS SR 4.3.1.1.1 could not be performed. Licensee management did not provide sufficient guidance to operators concerning performance of channel checks on RCS loop flow instrumentation when it was known that the Loop 1 instruments were reading high on-scale or bouncing above the top of scale. Operators did not challenge the fact that Unit 1 Loop 1 RCS flow indicators had been drifting high making a valid channel check difficult to perform when the three indicators routinely indicated greater than 110%, the top of the calibrated instrument scale.

02 Operational Status of Facilities and Equipment

02.1 Detailed Walkdown of Unit 1 Train A Safety Injection (SI) System

a. Inspection Scope (71707)

The inspectors conducted a detailed walkdown of Unit 1 Train A SI System to independently verify its operability. In conjunction with the walkdown, the inspectors reviewed applicable system documentation, physically examined system components, reviewed the maintenance status, and TS impact of observed material deficiencies.

The inspectors reviewed and utilized (1) UFSAR Chapter 6.3, Emergency Core Cooling System, Revision 13, (2) Flow Diagram 1-47W811-1, Safety Injection System, Revision 52, (3) Emergency Core Cooling System Power Checklist, 1-SO-63-5, Att. 1, Revision 13, (4) Valve Checklist, Att. 2, Revision 19, and (5) an "EASI" Report of Open Preventive Maintenance Schedule for System 063, dated December 18, 1998, in the performance of a physical walkdown of accessible portions of the system.

b. Observations and Findings

During the walkdown, the inspectors verified that accessible valves in the main flow paths with visually verifiable positions were correctly positioned. No missing handwheels, bent stems, or adverse environmental conditions were observed. Major components appeared to be correctly labeled, lubricated, cooled and ventilated. Essential support systems (cooling, ventilation, lubrication, and air) were operational. The inspectors examined selected local/remote indicators, operators, pipe hangers,

and essential instrumentation and found no undocumented material issues or deficiencies which impacted system operability. Spaces were reasonably clean and free of debris, loose materials, ignition sources, flammable materials, and ancillary equipment interference.

A number of Essential Raw Cooling Water (ERCW) flow control valves were observed to have work requests and/or blocking tags attached. The inspectors evaluated the material deficiencies of several of the tagged components. Most of the deficiencies were associated with leaking or ruptured air operator diaphragms which, the inspector determined, did not appear to interfere with the operability of the SI System. The noted deficiencies were discussed with the system engineer.

c. Conclusions

Based upon a detailed walkdown of accessible portions of Unit 1 Train A SI System, the inspectors concluded that the system was operable and being maintained in an acceptable material condition.

O3 Operations Procedures and Documentation

O3.1 Insufficient Guidance in Procedure Revision

a. Inspection Scope (71707)

The inspector reviewed procedure 1-SI-OPS-000-002.0, Shift Log, Appendix A, Revision 42, regarding revisions to the procedure which permitted the use of computer points to perform RCS Loop 1 channel checks and to determine total reactor coolant flow.

b. Observations and Findings

On November 20, 1998, the licensee revised 1-SI-OPS-000-002.0 to permit the use of computer points, in lieu of control room instrumentation, to perform Unit 1 RCS Loop 1 channel checks and verification of RCS total flow rate. The procedure revision was initiated when control room Loop 1 flow instrumentation pegged off-scale high (See Inspection Report (IR) 50-327, 328/98-10).

On December 10, 1998, the inspector, while following up on the events of November 20, identified that the unit of measurement for the computer points, which had been added to the procedure revision, was "% delta P." The unit of measurement for the Loop 1 control room instrumentation and for the other three RCS loops is "% flow." The inspector observed that the procedure did not contain a NOTE to explain or correlate the two units of measurement. Although a Loop 1 channel check could have been performed using the computer points, total RCS flow for all four loops could not have been determined since different units of measurement would have been used. Inspectors verified that at no time from November 20 to December 10 did the licensee actually use the computer points to perform a channel check or to verify total RCS because normal flow indicators were being used. The licensee

subsequently revised 1-SI-OPS-000-002.0 to delete the computer points and initiated Problem Evaluation Report (PER) No. SQ981697PER to document the discrepancy in the units of measurement.

The inspector determined that Revision 42 to 1-SI-OPS-000-002.0 was inadequate in that it did not provide guidance regarding the use of different units of measurement for verification of total RCS flow. This failure to provide an adequate procedure constitutes a violation of minor significance and is not subject to formal enforcement action.

c. Conclusions

A violation of minor significance was identified for failure to provide adequate guidance in Revision 42 of 1-SI-OPS-000-002.0 regarding units of measurement for verification of total RCS flow.

O4 Operator Knowledge and Performance

04.1 Failure to Follow Emergency and Abnormal Operating Procedures

a. Inspection Scope (71707)

The inspectors reviewed the licensee's November 9, 1998, Unit 1 post-trip review supplemental findings and continued inspection activities in the areas of operator performance, procedural guidance, and pressure control using the steam generator atmospheric relief valves (ARVs). Preliminary inspection findings were documented in IR 50-327,328/98-10, Section 01.5.

b. Observations and Findings

At 11:39 a.m. on November 9, 1998, a Unit 1 automatic reactor trip occurred when the No. 1-IV 120 Vac Vital Instrument Power Inverter failed causing a loss of power to the Channel-IV reactor protection circuits. The loss of the Reactor Protection Channel-IV coincident with a tripped condition during testing on Reactor Protection Channel-II, resulted in a reactor trip.

The loss of vital instrument power also resulted in the loss of automatic and manual RCS pressure control, loss of the Main Condenser Steam Dump System, loss of automatic control function of all four steam generator (SG) power operated atmospheric relief valves (ARVs), loss of manual control of the ARVs for SGs 2 and 3, and a loss of reactor coolant normal letdown. Additionally, equipment failures not related to the loss of vital instrument power complicated the reactor trip recovery. The main feed pumps failed to stop and the backup pressure limit function of the ARVs for SGs 1 and 4 failed to open the valves at 1040 psig as designed. According to plant computer data, SG #4 ARV failed to actuate and #1 SG ARV cycled at 1065 psig.

Due to multiple losses of primary and secondary pressure control systems and operator inaction, RCS temperature and pressure increased above values specified in

the emergency operating procedures. At 11:53 a.m., RCS pressure was greater than 2260 psig; at 11:54 a.m., RCS temperature was greater than 552°F, the upper limits specified in emergency operating procedure (EOP) ES-0.1, Reactor Trip Response.

At 11:55 a.m., RCS pressure reached 2335 psig, the power operated relief valve (PORV) lift set point, and the PORV began to cycle. RCS pressure peaked at 2335 psig and RCS temperature peaked at 556°F, apparently limited by the cycling of the #1 SG ARV. RCS temperature and pressure remained above values specified in the EOP until vital instrument power was restored at approximately 12:17 p.m.

Based on a detailed review, the inspectors determined that, contrary to Step 3 of EOP ES-0.1., operators failed to "Monitor RCS temperatures stable at or trending to between 547°F and 552°F" and to "Dump steam using the atmospheric reliefs" when RCS temperature was "greater than 552°F and rising." RCS temperature exceeded 552°F for a period of approximately 23 minutes. Section 2.4, Step 1.a. of Abnormal Operating Procedure (AOP)-P.03, Loss of Unit 1 Vital Instrument Power Board, which was being concurrently implemented, required operators to "Stabilize RCS temperature... using manual control of SG Loops 1 and 4 atmospheric relief valves." The licensee stated that operators, believing automatic pressure control operational, left ARVs in automatic. The failure of the operators to follow EOP requirements and take action to control RCS temperature is identified as one example of a violation (VIO 50-327/98-11-02).

In addition, the inspectors determined that, contrary to Step 8.b.2 of ES-0.1, (foldout for EOP ES-O.1) operators failed to take action to "Control pressure using one pressurizer PORV" when pressure was "greater than 2235 psig and rising." As a result, the pressurizer PORV cycled five times and RCS pressure exceeded 2235 psig for approximately 25 minutes. The failure of the licensee to follow EOP requirements to control RCS pressure is identified as a second example of VIO 50-327/98-11-02.

The licensee stated that controlling pressure using a PORV to automatically control pressure at 2335 psig was acceptable to meet the intent of this procedure step. However, step 8 of EOP ES-O.1 requires the operators to "Check RCS pressure control: Pressurizer pressure stable at or trending to 2235 psig (between 2210 and 2260 psig." The inspectors noted that control of pressure using a PORV in automatic at a control set point of 2325 psig would not meet the specified control band in EOP ES-O.1 and that manual operation was necessary.

The inspectors reviewed the Westinghouse Owners' Group Emergency Operating Procedure (WOG EOP) guidelines, the licensees' EOP ES-0.1 basis document (ES-0.1 BD), and Emergency Procedure User's Guide, EPM-4, Revision 5, to determine the written bases for RCS pressure and temperature control, and plant parameter control in general, during implementation of EOPs.

Regarding RCS temperature control, the WOG EOP states, "The operator should verify that RCS temperature is reduced to no-load... If RCS temperature is greater than no-load and increasing, then steam dump from the secondary must be increased for decay heat removal." The ES-0.1 BD states, "If RCS temperature is greater than

no-load and increasing, then steam dump from the secondary must be increased for decay heat removal."

Regarding RCS pressure control, the WOG EOP states, "If pressure is high, the operator should take action to reduce and control pressure." The ES-0.1 BD states, "If pressure is high, the operator should take action to reduce and control pressure."

Regarding plant control in general, the WOG EOP states, "The foldout page provides a list of important items that should be continuously monitored. If any of the parameters exceed their limits, the appropriate operations should be initiated." The ES-0.1 BD states two of its major action categories as: (1) "Ensure the primary system stabilizes at no-load conditions," and (2) "Ensure the secondary system stabilizes at no-load conditions." EPM-4, Section 3.4, Management Expectations, states. "When a parameter is approaching a protective action set point in an uncontrolled manner, the operator is expected to: (1) Evaluate the parameter magnitude and trend", and (2) Take actions as necessary to place the plant in a safe condition without relying solely on automatic actions."

Based on the written guidelines, the inspectors determined that plant operators were expected to take an active role in plant control when automatic plant control systems failed to stabilize plant parameters within prescribed operating bands. However, the licensee stated that no operator actions were necessary as long as plant conditions were stable, regardless of whether the plant was stable within or outside of the prescribed limits.

PER No. SQ981581PER, issued to evaluate problems during the event, characterized AOP-P.03 guidance as "generally acceptable" but identified the following procedure enhancements for corrective action:

- The procedure required the operator to STABILIZE RCS temperature at present value USING manual control of SG loops 1 and 4 ARVs but did not provide a stabilized temperature band in which to control temperature or any guidance to continue to monitor this parameter.

- The procedure directed placing the ARVs for S/Gs 2 and 3 in the closed position, thereby disabling their backup pressure limiting function which would otherwise have been operational.

- The procedure lacked guidance to continuously monitor pressurizer pressure following the loss of automatic pressure control.

- The procedure conflicted in areas with EOP ES-0.1.

- The procedure did not address the affects of loss of channel IV AC power on Chemical Volume Control System letdown instrumentation and on recovery of pressure control on SGs and pressurizer.

- The procedure did not provide a list of essential equipment impacted.

- The procedure did not identify all of the equipment that must be taken out of automatic control until power is restored to the board, nor did it provide guidance to allow time for automatic circuits to reset prior to placing the controls in automatic.

The inspectors identified the licensee's failure to provide an adequate procedure as a violation. This non-repetitive, licensee-identified and corrected violation is being treated as a Non Cited Violation (NCV) consistent with Section VII.B.1 of the NRC Enforcement Policy. This issue is identified as NCV 50-327/98-11-03.

c. Conclusions

A violation was identified with two examples of failure to follow EOP ES-0.1 when operators failed to take actions required by procedure to control RCS temperature and pressure following a reactor trip. These violations are of concern because they indicate a weakness in licensed operator's understanding and adherence to emergency operating procedures. In addition not taking manual control of steam dumping (ARVs) to control temperature and manual control of the PORVs to control RCS pressure placed an unnecessary challenge on the primary and secondary system relief valves to properly reseat after each actuation.

An NCV was identified for failure to provide an adequate abnormal operating procedure (AOP-P.03), contributing to the failure to control RCS temperature and pressure following a reactor trip.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) Inspection Follow-Up Item (IFI) 50-327/98-10-01: Follow-up on post-trip actions for Unit 1 trip of November 9, 1998. The inspectors initiated this IFI to address the licensee's post-trip review supplemental findings and to address inspector questions concerning management expectations, operator performance, procedural guidance, and the malfunctioning SG ARVs. This item is further discussed in Section O4.1.

O8.2 (Closed) Unresolved Item (URI) 50-327/98-10-02: Review licensee's actions related to failure of Unit 1 RCS loop 1 flow indicators. This item is further discussed in Section O1.3.

O8.3 (Closed) Licensee Event Report (LER) 50-327/98004: Failure to perform a surveillance within the required time interval due to a leaking vent valve. This event is further discussed in Section O1.3. No new issues were revealed by the LER.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726 & 62707)

The inspectors conducted frequent reviews of ongoing maintenance and surveillance activities.

b. Observations and Findings

The inspectors observed and/or reviewed all or portions of the following work orders (WOs) and/or surveillances:

- WO 98-008426 — Inspection/Cleaning of EDG 2A-A Battery
- 0-PI-EBT-082-238.4 — Modified Performance Testing of 125 Vdc EDG Batteries-2A-A, Revision 2
- 0-PI-MDG-082-102.M — Diesel Generator Monthly Mechanical Inspections, Revision 1
- 1-SI-SXX-068-155.0 — RCS Flow Verification, Revision 3
- 1-SI-ICC-068-06D.3 — Channel Calibration of Loop 1 Reactor Coolant Flow channel F-68-6D (F-416) Protection Set iii, Rack 9, Revision 5

c. Conclusions

The above maintenance and surveillance activities were completed in accordance with procedures and performed by knowledgeable personnel.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Completion of EDG Battery Replacement

a. Inspection Scope (62707)

The inspectors observed portions of the implementation and the final completion of EDG battery replacement.

b. Observations and Findings

The inspectors documented in IR 50-327, 328/98-08 the licensee's plan to replace the batteries on all four EDGs and concluded in that inspection report that the licensee had successfully implemented the initial phase of DCN M13972A. On December 16, 1998, the inspectors observed the completion of the battery replacement DCN when EDG 2A-A was connected to its new battery. The inspectors had previously observed various phases of the other three EDG battery replacements.

c. Conclusions

The licensee successfully implemented a design change to replace the batteries on all EDGs.

M8 Miscellaneous Maintenance Issues

M8.1 Electrical Breaker Testing and Maintenance

a. Inspection Scope (62700)

This portion of the inspection was conducted to review the licensee's breaker testing and maintenance program due to concerns with breaker performance and the effects of that performance on plant operations. The inspector reviewed breaker-related findings in recent NRC inspection reports and two breaker licensee self-assessments and a Quality Assurance (QA) assessment to determine the types of problems which had been identified [reference self-assessments SA-E&M-98-009 (April 1998) and SQ-SA-E&M-98-028 (Draft - August 1998), QA assessment NA-SQ-98-052 (October 1998)]. The inspector also reviewed the corrective actions and corrective action status for the licensee's April self-assessment. The inspector reviewed the program procedure (0-TI-SBR-000-001.0, "Breaker Testing and Maintenance Program," Revision 0), the status of overdue breaker preventive maintenance, scheduling of breaker preventive maintenance under the new program, and observed work on the 480 volt shutdown board 2A1-A alternate feeder breaker.

b. Observations and Findings

The licensee conducted a self -ssessment of the breaker program in April 1998. Review of the self-assessment (SA-E&M-98-009) determined that the assessment was very thorough, and identified several significant findings, which have provided the impetus for significant changes in the breaker program, maintenance, and testing procedures.

As a result of the assessment, the licensee issued more than 30 tracking items to track completion of corrective actions. The inspector reviewed the corrective action and status of these items, and determined that actions to this point have focused primarily on improving program procedures. The inspector determined, however, that operability evaluations had been completed for issues relating directly to the hardware in the plant. The inspector also determined that most of the 480V and 6.9KV breakers had not been subjected to the upgraded procedures. As a result, the inspector requested additional information on the status of the overall breaker improvement program. The following data was obtained:

Breaker type		Number of breakers	Status
6.9KV	SD	180	79 inspected to new requirements
480V	SD	330	89 inspected to new requirements
Cooling Tower		19	Licensee writing procedure
250V DC		18	Licensee writing procedure

6.9KV Start	9	All 10 year PM done
125V Battery	8	4-Licensee writing procedure, 4-complete
CRDM MG Set	4	Licensee writing procedure
HP Fire Pump	2	Licensee writing procedure
Exciter Field	2	Licensee writing procedure
5th Vital Battery	1	Licensee writing procedure
Molded Case	5000	Licensee writing procedure-approximately 1000 classified as Cat 1 (most important)

This data clearly indicated that considerable amount of work has been completed, however, the results of that work has not been applied to the hardware in the plant. Until the remaining breakers are inspected and tested to the improved procedures, the reliability of these breakers and their affect on plant performance remained a concern.

c. Conclusions

The licensee made significant improvements in the breaker testing and maintenance program from April - December 1998. However, until all the breakers in the plant have been inspected and tested to the new program requirements, their reliability and affect on plant performance remains a concern.

III. Engineering

E3 Engineering Procedures and Documentation

E3.1 Ice Condenser Modifications Review

a. Inspection Scope (37550)

The inspector reviewed documentation of safety evaluations for completed DCNs, Section 6.5 of the UFSAR, UFSAR change packages, and held discussions with licensee personnel to verify that modifications were properly evaluated and conformance with the UFSAR was assured. The inspector selected DCNs from the licensee's list which appeared, from the description, to have a possibility of effecting the USFAR. The inspector also confirmed that changes observed during a recent field inspection were properly controlled and evaluated. The following documents were reviewed:

- UFSAR Section 6.5, Amendment 13,
- DCN M08402B, Lower Inlet Doors at Ice Condenser, Unit 2 (this modification included removal of portions of the door sill flashing, replacement of insulation, raising the turning vanes, and modification of the door frame to assure door clearance),

- DCN M08924C, Ice Condenser, Unit 1 (this modification allowed jacking of the wear slab for clearance, modification of the door frames as needed, raising the turning vanes, modification of floor drains, sealing of wear slab joints and cracks, and removal of core samples from each bay),

- DCN M12682A, Ice Condenser Wear Slab Modified, Unit 1 (this modification removed the wear slab and foam concrete from Bays 13, 14, and 15 and replaced it with continuous concrete and authorized chipping of concrete in other bays),

- DCN M13931A, Install Well Point Permanently, Unit 1 (this modification added well points to Bays 5, 10-12, 16-19, and 21 and authorized trimming of angles beneath doors and chipping of concrete),

- Engineering Change Notice (ECN) L5921, Place a Metal Screen Over the Discharge Opening of the Ice Condenser Return Air Ducts, Revision 1,

- UFSAR Change Package Nos. 14-34, 15-22, and 15-34,

- Temporary Alteration Control Form (TACF) No, 1-92-0017-061, Installation of Floor Monitoring System for Unit 1, Revision 0,

- TACF No. 2-92-0022-061, Installation of Floor Monitoring System for Unit 2, Revision 0,

- Procedure 0-PI-SXX-061-001.0, Ice Condenser Lower Plenum Floor Monitoring, Revision 4.

b. Observations and Findings

The licensee's safety evaluations were adequate and identified no unreviewed safety questions. The inspector agreed with the licensee's conclusions. Appropriate UFSAR changes had been implemented or change packages for incorporation into the next amendment had been initiated for the DCNs reviewed. The inspector noted that TS ice weights were less than the UFSAR stated and confirmed that a change package had been submitted to assure this change was incorporated into the next amendment. The licensee had identified a number of UFSAR enhancements as a result of self-assessment processes for which change packages had been submitted. Also Change Package 15-22 included changes resulting from recent analyses which included authorization to remove the top basket cruciform, an alternate basket support arrangement, and changes in the ice basket screw material properties.

Recent field observations had noted that screens had been attached at the opening of the air return ducts in the upper plenum and a floor monitoring system had been installed in the lower plenum. The inspector confirmed that the licensee had adequately evaluated the installation of the screens via an ECN. The floor monitoring system had initially been installed via temporary modifications and later incorporated into the procedure listed above. The inspector reviewed the safety assessments for these modifications and considered that one question had not been fully documented.

Approximately 13,000 feet of cable had been required for the system and the analysis stated "The cables are not adequate for long term use inside containment due to exposure to radiation." which implied that some deterioration could occur such that the cable jacket could separate and be available during an event to clog drains or sumps. The licensee evaluation determined that the debris would not clog the containment sump but made no statement about the drains out of the lower plenum of the IC. The licensee stated that the jacket failure mode from radiation would result in embrittlement and small pieces of material which could be dislodged would easily exit through the drains which have one inch openings in the grating. Subsequent to the inspectors questioning, the licensee documented this justification on PER No. SQ990025PER which the inspector reviewed and considered to be adequate to address the inspector's concern. The licensee's judgement appeared to be reasonable and no regulatory issues were identified.

c. Conclusions

IC modifications were properly evaluated for conformance to the UFSAR description of the system and required changes to the UFSAR were implemented. The licensee appropriately initiated changes to the UFSAR where clarifications were needed based on self-assessments and recent analyses. The licensee adequately addressed a concern regarding the effects of deteriorated cables on the ice condenser drains.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on January 8, 1999, and for a region based inspection on December 18, 1998. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Bajestani, Site Vice President
C. Burton, Engineering and Support Systems Manager
H. Butterworth, Operations Manager
J. Gates, Site Support Manager
E. Freeman, Maintenance and Modifications Manager
J. Herron, Plant Manager
C. Kent, Radcon/Chemistry Manager
D. Koehl, Assistant Plant Manager
B. O'Brien, Maintenance Manager

P. Salas, Manager of Licensing and Industry Affairs
M. Lorek, Acting Engineering & Materials Manager

NRC

M. Shannon, Senior Resident Inspector, Sequoyah
K. VanDoorn, Senior Resident Inspector, Watts Bar
D. Starkey, Acting Senior Resident Inspector, Sequoyah
R. Telson, Resident Inspector, Sequoyah
R. Gibbs, Senior Reactor Inspector, RII

INSPECTION PROCEDURES USED

IP 37550: Engineering
IP 61726: Surveillance Observations
IP 62700: Maintenance
IP 62707: Maintenance Observations
IP 71707: Plant Operations
IP 92901: Followup - Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-327/98-11-01	VIO	Failure to enter TS 3.0.3 when LCO for TS 3.3.1.1 was not met (Section O1.3).
50-327/98-11-02	VIO	Failure to follow EOP resulting in exceeding RCS pressure and temperature limits (Section O4.1).
50-327/98-11-03	NCV	Failure to provide adequate AOP guidance (Section O4.1).

Closed

50-327/98-10-01	IFI	Follow-up on post trip actions for Unit 1 trip of November 9, 1998 (Section O8.1).
50-327/98-10-02	URI	Review licensee's actions related to failure of Unit 1 RCS Loop 1 flow indicators (Section O8.2).
50-327/98-004	LER	Failure to perform a surveillance within the required time interval because of a leaking vent valve (Section O8.3).
50-327/98-11-03	NCV	Failure to provide adequate AOP guidance (Section O4.1).

LIST OF ACRONYMS USED

AOP	-	Abnormal Operating Procedure
ARV	-	Atmosphere Relief Valve
AUO	-	Assistant Unit Operator
DCN	-	Design Change Notice
DNB	-	Departure from Nucleate Boiling
ECN	-	Engineering Change Notice
EDG	-	Emergency Diesel Generator
EOP	-	Emergency Operating Procedure
ES	-	Emergency Subprocedure
ERCW	-	Essential Raw Cooling Water
IFI	-	Inspection Followup Item
IR	-	Inspection Report
KV	-	Kilovolt
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
NCV	-	Non-cited Violation
NRC	-	Nuclear Regulatory Commission
NRR	-	Nuclear Reactor Regulation
PER	-	Problem Evaluation Report
PI	-	Periodic Instruction
PORC	-	Plant Operations Review Committee
PORV	-	Power Operated Relief Valve
psig	-	Pounds Per Square Inch-gauge
QA	-	Quality Assurance
RCS	-	Reactor Coolant System
SG	-	Steam Generator
SI	-	Safety Injection
SR	-	Surveillance Requirement
TACF	-	Temporary Alteration Change Form
TS	-	Technical Specification
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
V	-	Volt
Vac	-	Volts alternating current
VIO	-	Violation
WO	-	Work Order
WOG EOP	-	Westinghouse Owners Group Emergency Operating Procedure