U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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| License Nos: | DPR-77, DPR-79 |
| Report Nos: | 50-327/96-09, 50-328/96-09 |
| Licensee: | Tennessee Valley Authority (TVA) |
| Facility: | Sequoyah Nuclear Plant, Units 1 & 2 |
| Location: | Sequoyah Access Road<br>Hamilton County, TN 37379 |
| Dates: | July 28 through September 14, 1996 |
| Inspectors: | M. Shannon, Senior Resident Inspector<br>W. Holland, Senior Resident Inspector<br>R. Starkey, Resident Inspector<br>J. Blake, Reactor Inspector, (Sections M3.1, M6.1, M8.1, E2.1)<br>G. MacDonald, Reactor Inspector,(Sections M1.2,M1.3, & M2.4)<br>K. VanDoorn, Senior Resident Inspector-Watts Bar, (Section 03.1) |
| Approved by: | M. Lesser, Chief<br>Reactor Projects Branch 6<br>Division of Reactor Projects |

Enclosure 2

# EXECUTIVE SUMMARY

Sequoyah Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-327/96-09, 50-328/96-09

This integrated inspection included aspects of licensee operations, maintenance, engineering, plant support, and effectiveness of licensee controls in identifying, resolving, and preventing problems. In addition, it includes the results of announced inspections by engineering and maintenance inspectors.

## Operations

- Negative observations were noted in the areas of operation's log keeping detail, emergency diesel generator starting air system operation, operation's log keeping status control, and guidance in operator rounds (Sections 01.2 and M1.1).

- Back-filling of pressurizer level transmitters presented a potential safety hazard to personnel and could result in a breach of the reactor coolant system (RCS) (Section 02.2).

- A weakness was identified in the control of certain engineering documents provided to control room operators (Section 03.1).

- A non-cited violation (NCV) was identified for the placing of an Emergency Gas Treatment System (EGTS) damper control switch in the wrong position which rendered the "A" train of EGTS inoperable for 2 hours and 43 minutes (Section 03.2).

- Technical Specification (TS) wording does not accurately reflect the current shift hours worked by operations personnel. However, the licensee has been in compliance with the TS guidelines regarding use of overtime and has initiated a proposed change to TS to clarify normal shift hours (Section 08.1).

## Maintenance

- Maintenance and surveillance activities observed were satisfactorily performed in accordance with licensee procedures. A weakness in Emergency Diesel Generator (EDG) maintenance trending was noted regarding not performing any compensatory measures for failed EDG cylinder exhaust gas temperature parameters (Section M1.2).

- Several completed work orders were reviewed and the level of detail of work documentation was adequate but not thorough. A minor documentation weakness was noted in a mechanical maintenance work order which was corrected by the licensee (Section M1.3).

- An ERCW pump discharge check valve stuck open due to wear and resulted in a system backflow of approximately 3000 gallons per minute. Subsequently, engineering determined that the stuck open ERCW pump discharge check valve had been installed incorrectly (Section M1.4).

- Repetitive equipment problems caused added operator burden and impacted maintenance resources, operation's switching and tagging resources, and day-to-day operations (Section M2.3).

- Corrective action for the Emergency Diesel Generator (EDG) Governor Booster Servomotor was satisfactory (Section M2.4).

- Steam Generator records indicated that the licensee has implemented a comprehensive program to minimize stress-related degradation of Steam Generator tubes (Section M3.1).

- The licensee's Steam Generator organization has done a very good job of reviewing their inspection and repair options, and then soliciting plant and corporate management support for the options selected (Section M6.1).

Engineering

- After identification of initial concerns based on the engineering evaluation for a Part 21 potential problem associated with material, the licensee took appropriate positive actions to determine the issue did not affect Sequoyah (Section E2.1).

- A weakness in the licensee's process for design control of system operational status was identified. Sample valves located in the Unit 1 hot sample room for the Safety Injection system were in poor material condition and presented potential housekeeping problems. In addition, this portion of the sample system was not formally dispositioned as to its operational status in the plant (Section E2.2).

- The practice of venting the residual heat removal (RHR) system prior to calculating the volume of gas in the system did not provide an accurate representation of the total amount of gas in the RHR system (Section E2.3).

- A violation was identified for untimely and inadequate corrective actions associated with the failures of the EDG starting air compressor control switches (Section E4.1).

- A weakness was identified for the inadequate root cause evaluations associated with the initial EDG starting air compressor control switch failures (Section E4.1).

- Weak engineering support and maintenance was indicated by repetetive equipment problems which added operator burden and impacted maintenance resources (Section M2.3).

Plant Support

- The licensee did not take adequate immediate corrective actions for a transient fire load issue identified during the week of July 8 - 12, 1996. Appropriate corrective action was only taken after the Nuclear Regulatory Commission (NRC) commenced additional review of the issue on July 30, 1996 (Section F1.1).

## Report Details

Summary of Plant Status

Unit 1 began the inspection period in power operation. The unit operated at power for the duration of the inspection period.

Unit 2 began the inspection period in power operation. The unit operated at power for the duration of the inspection period.

## 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 acceptable. Specific events and noteworthy observations are detailed in the sections below.

O1.2 Emergency Diesel Generator Starting Air System Operation

a. Inspection Scope (71707)

The control room logs were reviewed in order to determine the frequency at which the EDG starting air system relief valves were lifting and to determine what operational problems were being experienced as a result of the various starting air compressor malfunctions. The supporting documentation for the EDG starting air compressor control switch problems is detailed in Section E4.1.

b. Observations and Findings

While reviewing documentation and actions associated with the EDG starting air compressor control switch failures, various observations related to the conduct of operations were made. The following items were identified during the review:

- The control room logs and the associated PERs did not always identify which relief valve was lifting or identify the affected compressor unit. The lack of engineering's and management's knowledge that the receiver tank/system reliefs were lifting appeared to contribute to the licensee's slow implementation of corrective actions.

- Operation's actions, in responding to deficient conditions, were considered to be weak in that on August 23 the 2A2 EDG starting air system was found relieving and the compressor control was not

placed in "off" and approximately 8 hours later the relief valve was found relieving again. In addition, on August 4 and again on September 10, after the 2A2 EDG stating air compressor was placed in "off", the starting air system alarmed on low pressure.

- The September 8, control room logs documented that at 03:07 p.m., "fire operations" reported that the 1A-A EDG air relief valve was actuated. The logs for 03:34 p.m., documented that the compressors were found in "off" and the relief valves were seated. The logs did not document control room directions to place the compressors in "off", did not document that the switches had been placed in "off" following the 03:07 p.m., entry, and did not document who placed the switches in "off".

- The logs noted that the operator increased receiver tank pressure to 305 psig on two occasions. The normal operating band for receiver pressure control was 250-300 psig and the low pressure alarm actuates at approximately 250 psig. The logs only consider an abnormal condition when pressure drops to less than 240 psig and does not give the operator a limit for a high pressure abnormal condition. Routinely, log reading limits are based on the automatic operational setpoints for a system to ensure abnormal operation is identified prior to the development of more serious deficiencies.

c. Conclusions

The failure to identify the specific relief valves that were lifting in the control room logs was considered to be a negative observation.

The failure to maintain the starting air system within the normal operational band when operational problems are known was considered to be poor implementation of compensatory measures.

The lack of status control in the control room logs was considered to be a negative observation.

The lack of clear guidance in operator rounds was considered to be a negative observation.

## O2 Operational Status of Facilities and Equipment

O2.1 Main Control Room Alarms, Indications, and Control Deficiencies

a. Inspection Scope (71707)

During the period of August 23-28, 1996, the inspectors walked down the main control room boards and the common boards of each unit. This walkdown, accomplished over several days, had as its purpose to identify all the deficiencies, (Work Requests (WR), disabled annunciators,

caution orders), on each unit and to determine Operator's awareness of the deficiencies.

b. Observations and Findings

The inspectors noted 54 WR stickers in the Unit 1 horseshoe area, four WRs on the nuclear instrumentation back panel and 39 WRs on the common control board (panels 1-M-15 through 0-M-15). These panels contained a total of 12 disabled or partially disabled annunciators and 12 posted caution orders. When questioned about specific deficiencies, operators did not always have a ready explanation for the deficiency, but generally knew where to look to find the requested information.

c. Conclusions

The inspectors concluded that the number of deficiencies, as noted by the number of WRs, disabled annunciators, and caution orders, made it difficult for an operator to be cognizant of the nature of each deficiency, thus placing an unnecessary work load on licensed operators.

O2.2 Backfill of Pressurizer Level Transmitter

a. Inspection Scope (71707)

The inspectors reviewed a recent Unit 1 evolution involving the backfilling of a pressurizer (PZR) level transmitter reference leg and the licensee's practice of bypassing and tripping related instrumentation to accomplish the evolution.

b. Observations and Findings

On August 28, 1996, the licensee documented in Problem Evaluation Report (PER) No. SQ962300PER a level deviation between the three Unit 1 Main Control Room (MCR) PZR level instruments (1-LI-68-320, 335, and 339). The maximum observed level deviation between the instruments was 4% while the maximum allowed deviation was 5%. On August 29, the licensee initiated action to backfill the reference leg of 1-LT-68-320 to correct the problem.

The design of the PZR level/pressure instrumentation is such that 1-LT-68-320 shares a common reference leg with two PZR pressure transmitters, 1-PT-68-322 and 1-PT-68-323. In order to fill the reference leg of 1-LT-68-320, the two pressure transmitters had to be bypassed/tripped. TS 3.3.1, Reactor Trip System Instrumentation, Table 3.3-1, requires that three out of four PZR pressure channels be operable in Modes 1 & 2, with two channels required to initiate a unit trip. The licensee determined that a recent change to the TS Bases allows one channel to be bypassed, which would make that channel inoperable, and allows the second channel to be tripped. The TS Bases states that the placing of a channel in the tripped condition provides the safety function of the channel and if the channel is tripped for testing and no other condition would have indicated inoperability, the channel should not be declared inoperable.

Based upon the licensee's TS interpretation, operators bypassed 1-PT-68-322 and tripped 1-PT-68-323 for the backfilling evolution. The licensee successfully completed the backfilling in less than two hours and returned the protection system to a normal alignment.

The inspectors questioned the licensee on the necessity of backfilling the level transmitter since the reference leg is designed with a condensing pot would should ensure that the reference leg remains filled. The licensee is evaluating the root cause as to why the reference leg is not being maintained filled by the condensing pot.

c. Conclusions

The inspectors discussed with the licensee the licensee's interpretation of TS 3.3.1.1 which allows bypassing/tripping of two of four instruments in the same protection set. The inspectors are continuing to determine if the licensee was correctly interpreting TS 3.3.1.1. This issue is identified as Unresolved Item (URI) 50-327, 328/96-09-01, Determine Whether TS 3.3.1.1 Allows One Pressurizer Pressure Channel to Be Bypassed at the Same Time that a Second Pressurizer Pressure Channel is Tripped.

The inspectors noted that during the backfilling evolution that a portable high pressure pump was used to backfill the reference leg. At times during the evolution the pump was exposed to RCS pressure. The inspectors considered that this evolution presented a potential safety hazard to personnel and could result in a breach of the RCS.

## O3 Operations Procedures and Documentation

### O3.1 Uncontrolled Guidance Found in Main Control Room (MCR) (71707)

a. Inspection Scope (71707)

On August 15, 1996, the inspector conducted a review of engineering documents available for operator use/reference in the MCR.

b. Observations and Findings

The inspector noted that two binders containing miscellaneous information from the engineering group were in the MCR. A binder in the Unit 1 area was marked "Assistant Shift Operations Supervisor (ASOS) Letters of Interest." It contained 38 different documents providing information and guidance to operators. These included memoranda, single pages of information with an engineering signature, Technical Support Investigation Requests (TSIRs), and portions of PERs. Some had hand written notes. One Unit 1 Senior Reactor Operator (SRO) indicated that they might operate in accordance with this guidance, however, they would not operate outside of procedures. In the Unit 2 area the binder was marked "TSIR, Action Plans". The licensee sometimes develops Action Plans to direct activities to be performed to address problems noted in

TSIRs. The Unit 2 binder contained various documents similar to the Unit 1 binder. although, no Action Plans were in the book. Information was organized by system in this binder.

c. Conclusions

The inspector noted that these documents appeared to have no attendant controls by operation's management to evaluate whether the guidance was to be followed, whether the information was current, whether a Shift Order or Standing Order was appropriate, and to assure consistent information was given to operators. The inspector considered this to be a weakness in control of information to operators. This observation was discussed with licensee management.

O3.2 Inoperable Emergency Gas Treatment System Train (EGTS)

a. Inspection Scope (71707)

Inspection Report 50-327,328/96-08 identified an unresolved item (URI) 50-327/96-08-01, which discussed a mispositioned switch in the EGTS on July 24, 1996. The mispositioned switch rendered the EGTS train inoperable for 2 hours and 43 minutes. Further review of the post maintenance and operational procedures, in addition to a review of the corrective actions in the associated PER, were conducted.

b. Observations and Findings

Initial reports indicated that both trains of EGTS were inoperable during this event. However, further review noted that, although the "B" train was administratively inoperable because management review of the testing had not been completed, the system was aligned and capable of performing its safety function. This precluded the system from being inoperable according to TS and eliminated the potential TS 3.0.3 entry.

The inspectors noted that the operators had placed control switch 1-HS-65-10 in the wrong position and also had improperly and independently verified the switch in the wrong position. Following a detailed review of the procedure, the inspectors concluded that the operator actions were the result of an inadequate procedure. While the procedure specified the final damper position, it did not specify the final switch position.

The inspectors also noted that the majority of safety-related control room control switches, spring return to their safety positions, however, not all of the switches associated with the EGTS spring return to their safety positions. For these switches additional procedural guidance would be warranted to ensure proper positioning.

c. Conclusions

The placing of the EGTS control switch in the wrong position, which rendered the "A" train of EGTS inoperable for 2 hours and 43 minutes, is a violation of NRC requirements. The operator, who mispositioned the control switch, identified the error during shift turnover and promptly reported the error to shift management. Subsequently, the licensee has identified 5 procedures which do not adequately control hand switch configuration. The deficient procedures have been or will be revised prior to future use. Based on the operator's prompt reporting of this error and the corrective actions detailed in PER SQ962041PER, this licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 327/96-09-02).

## O8 Miscellaneous Operations Issues

### O8.1 Proposed Technical Specification Change Regarding Normal Work Day

a. Inspection Scope (71707)

During this inspection period the inspectors reviewed the licensee's established working hours, as described in TS 6.2.2, Facility Staff.

b. Observations and Findings

TS 6.2.2.g (working hours of unit staff who perform safety-related functions) states, in part, that the objective shall be to have operating personnel work a normal 8-hour day, 40-hour week while the unit is operating. Since the last refueling outage (U2C7) which ended in the Spring of 1996, SROs have worked a 12-hour rotating shift while Reactor Operators (RO) and Assistant Unit Operators (AUO) have worked an 8-hour shift.

The licensee agreed with the inspector that the current TS wording does not accurately reflect the current, or possible future, shift hours worked by operations personnel. As a result, on August 19, 1996, the licensee initiated a TS amendment which will be worded to more clearly reflect the normal work shift hours for operations personnel.

c. Conclusions

The inspector concluded that this proposed TS change was administrative in nature and that the licensee has been in compliance with the guidelines of TS 6.2.2.g regarding use of overtime.

# II. Maintenance

## M1 Conduct of Maintenance

### M1.1 General Comments (62703)

a. Inspection Scope (61726 & 62703)

The inspectors observed and/or reviewed all or portions of the following work activities and/or surveillances:

- 2-SI-SXV-003-219.0 — Auxiliary Feedwater Check Valve Test During Operation
- 2-SI-OPS-030-286.0 — Cumulative Time That Containment Purge Supply and Exhaust Isolation Valves Are Open
- 2-SI-SXP-003-201.B — Motor Driven Auxiliary Feedwater Pump 2B-B Performance Test
- WO9632986 — Lube & Inspect Charging Pump and Charging Pump Speed Increaser
- WO9636019 — Install Refurbished Reactor Trip Breaker in Unit 2.

b. Observatiors and Findings

The inspectors noted that the work activities and the performance of surveillance activities were adequately performed.

c. Conclusions

The inspectors noted that the control room logs, associated with surveillance 2-SI-OPS-030-286.0, were incomplete. The logs did not always document the initiation and completion of the various containment purge evolutions and this was considered to be a negative observation.

### M1.2 Observation of Maintenance and Surveillance Activities

a. Inspection Scope (62703)

Maintenance activities were observed to determine if the activities were performed in accordance with licensee procedural requirements. The

inspection scope included observation of portions of the following maintenance activities by a NRC Region II maintenance inspector:

- WO963502000 — Electrical maintenance implementation of relay protection design change of 1C Condenser Cooling Water (CCW) Pump Motor
- WO963548400 — Mechanical corrective maintenance on auxiliary building fire door
- WO963534500 — Customer Group corrective maintenance to disable gas operated relay protection and install sudden pressure relay protection for Main Bank Transformer 1C
- WRC336606 — Troubleshooting corrective maintenance by the Fix-It-Now team to locate a ground on electrical panel LC104
- MI-4.2.3/SI-102 — Mechanical preventive maintenance monthly mechanical inspection of EDG 2A-A

b. Observations and Findings

The maintenance activities observed were required to meet the applicable requirements of Site Standard Practice (SSP)-6.1, Conduct of Maintenance, SSP-6.2, Maintenance Management System, and SSP-6.25, Maintenance Management System Performance of Work Orders.

The maintenance activities observed were satisfactorily performed. Work was accomplished per the work documents and the work package instructions were actively in use. Drawing and procedure revisions were verified prior to use. Personnel qualifications were checked for the Maintenance Instruction (MI)-4.2.3/Surveillance Instruction (SI)-102 monthly Preventive Maintenance (PM) inspection of EDG 2A-A and the personnel performing the work were task qualified. Personnel were knowledgeable on the equipment and the procedures. Measuring and Test Equipment (M&TE) was checked and verified to be in calibration. The pre-job briefing for WO963502000 was considered good.

During review of the work package for the 2A-A EDG monthly mechanical inspection work activity, the inspector noted a weakness in EDG trending. Procedure MI-4.2.3 obtains cylinder exhaust temperature data for trending purposes. The procedure requires that adjacent cylinder exhaust temperature differential be ≤ 100 degrees F. Turbocharger inlet temperature differential was required to be ≤ 200 degrees F. If the cylinder exhaust temperature differential exceeds 100 degrees F or turbocharger inlet temperature differential exceeds 200 degrees F then a work request is required to be initiated for resolution. If a WR already exists, then the procedure requires that the WR number be recorded in the procedure.

The inspector determined that cylinder No. 7 was reading 660 degrees F and the remaining cylinder temperatures ranged from 940-1000 degrees F. Existing WR 201222 written in June, 1995, documented this condition on engine 2A1 cylinder No. 7 and a condition of high turbocharger inlet temperature differential. Licensee WO 950658600 performed in February 1996, to implement WR C201222 determined that engine 2A1 turbocharger and cylinder No. 7 temperature parameters had open thermocouples or thermocouple wiring.

The cylinder exhaust temperatures were recorded for trending purposes to monitor engine performance. Low cylinder exhaust temperature readings or high cylinder exhaust temperature differential values could be due to failed indication circuitry or could be an indication of performance problems with the cylinder. High turbocharger inlet temperature differential could be due to failed indication circuitry or governor performance problems. The exhaust gas and turbocharger inlet temperature values were not utilized as part of EDG operability verification.

Discussions with licensee technical support and maintenance personnel indicated that while the temperature measurement conditions existed since June 1995, no attempt was made during the monthly inspections to utilize compensatory measures to obtain the data on these two temperature parameters.

The licensee operated EDG 2A-A from June 1995, until February 1996, without identifying that the problem was open thermocouples or thermocouple wiring. The licensee operated EDG 2A-A since June 1995, without utilizing any compensatory measures to obtain the 2A1 EDG engine turbocharger inlet and cylinder No. 7 exhaust temperature values for trending. This is considered a weakness in trending and performance monitoring of the EDG.

c. Conclusions

The maintenance and surveillance activities observed were satisfactorily performed in accordance with licensee procedures. A weakness was noted in EDG temperature parameter trending.

## M1.3 Review of Completed Work Orders

a. Inspection Scope (62703)

Selected work orders for completed work activities were reviewed to determine if the completed work met applicable procedural requirements and to determine the degree to which the activity was documented in the work order (WO). The following work orders were reviewed by a NRC Region II maintenance inspector.

- WO963548400 Mechanical corrective maintenance on auxiliary building fire door
- MI-4.2.3/SI-102 Mechanical preventive maintenance monthly mechanical inspection of EDG 2A-A
- WO963001700 Chemical and Volume Control System (CVCS) valve 2VLV-62-659 machining
- WO962806000 Non-return valve 2-FCV-005-0037 counter weight modification

b. Observations and Findings

A minor documentation error was noted in the work package for the 2A-A EDG monthly mechanical inspection. Procedure MI-4.2.3 requires that a work request be written if adjacent cylinder exhaust temperature differential exceeds 100 degrees F. EDG 2A-A cylinder No. 7 read 660°F while the rest of the cylinders read from 940-1000 degrees F. If an existing work request existed for the condition then the existing WR number was to be recorded. No work request was recorded and the inspector considered this an example of lack of attention to detail. The licensee corrected the work package. The documentation reviewed showed that except for the item mentioned the work was done according to the procedural requirements.

c. Conclusions

The level of detail of work documentation was adequate but not thorough. A minor documentation error was noted in one work order which was corrected by the licensee.

M1.4 ERCW Discharge Check Valve Stuck Open

a. Inspection Scope (62703)

The inspectors reviewed the licensee's actions related to repair of ERCW pump L-B discharge check valve.

b. Observations and Findings

On August 23, 1996, the licensee identified that the discharge check valve on ERCW pump L-B was leaking by, when the pump was stopped, at the rate of approximately 3000 gallons per minute (gpm). The licensee subsequently determined that the swing arm of the valve exhibited excessive wear which resulted in the valve not properly seating. The licensee also discovered that the valve had been incorrectly installed approximately two years ago. The inspector determined from the valve vendor's manual that the valve had in fact been installed incorrectly. Further discussions with the system engineer revealed that it could not be concluded that the incorrect installation resulted in the valve

failure. The valve was repaired and returned to service. The licensee initiated Problem Evaluation Report (PER) No. SQ962283PER to document the valve failure.

c. Conclusions

The inspectors concluded that the ERCW check valve had been installed incorrectly at some time in the past, but could not conclude that the incorrect installation resulted in its subsequent failure. The licensee plans to inspect the remaining seven ERCW discharge check valves at a future date. The corrective actions associated with the PER will be reviewed during a future inspection. This item is identified as Inspector Followup Item (IFI) 50-327, 328/96-09-03, Review Corrective Actions Related to ERCW Check Valve Failure, PER SQ962283PER.

M2.3 Equipment Material Condition and Reliability Issues

a. Inspection Scope (62703)

The inspectors noted that during shift relief/turnovers, the morning status meeting and while reviewing operator logs that a variety of systems and components appeared to be experiencing repetitive/multiple failures. A detailed review of the control room logs and site information reports (morning status meeting) was conducted, to identify those systems/components with multiple deficiencies. The operations logs and status reports covered the period from July 28 through September 14.

b. Observations and Findings

The operations logs, although not always detailed, provided the majority of the examples documented in the following section. The individual descriptions were taken from the unit operations logs or the site information reports and a detailed review of each item has not been performed by the NRC. The operations logs indicated that many of the items were corrected in a timely manner. While this list was intended to document the quantity and types of problems being experienced, it also was intended to focus on systems with recurring failures/problems. The following are examples of equipment failures/problems noted during the period, however, note that this list is not all inclusive.

- Various EDG starting air system relief valves were found relieving eight times (Section E4.1).

- At one point, only one of four primary water pumps was available to supply both units due to excessive seal leakage and vibration problems.

- Only one of four shutdown board room cooling fans was available due to a loss of freon from one chiller unit (two fans inoperable) and high vibration on one of the other fan units.

- Various reactor coolant pump (RCP) seal leakoff detectors (3 of 8) became stuck; twice during the inspection period, with a third occurrence just following the completion of this inspection period.

- The glycol chillers experienced multiple problems: on July 31, the "E" chiller had excessive vibration; on August 8, the "A" chiller was found tripped, on August 15, the "A" chiller tripped due to air in the system which could not be removed; on August 20, after filling and venting the "I" chiller, the operators could not keep it running; on August 20, maintenance replaced the "I" chiller control module due to shorting; on August 21, all of the chillers and pumps tripped due to low expansion tank level; on August 21, operators could not get the "D" chiller to restart; on August 26, the "H" chiller tripped for no apparent reason and could not be restarted, in addition, "there were no spare chillers available"; and on September 11, the "E" chiller was taken out of service for troubleshooting.

- The boric acid system experienced problems with flow oscillations, tripping thermal overloads, and slow controller operation.

- The main turbine oil systems experienced problems with low turbine Auto Stop Oil pressure and low EHC pressure.

- There were multiple leaks from the ERCW hypochlorite system: the 2A header on August 2, the 1A header on August 3, the 1B header on August 17, the 2A header on August 20, the 1A header on August 25, the 1A relief valve was found lifting on August 27 and the "A" skid discharge piping had a leak on September 9. In addition, on September 1, the supply breaker for the injection pumps kept tripping.

- The Control Rod Drive Motor (CRDM) automatic temperature control cooling valves were drifting closed and sometimes caused the fan cooling supply air to exceed the administrative limits of 110 degrees F.

- There were various computer problems during the period such as: the Integrated Control System (ICS) computer system had not been able to calculate core burnup since the system was installed; a digital link to the ICS computer for point U1118 failed causing an indicated increase of 10 Megawatts-Thermal (MWT) to the total power calculation; and the ICS computer calorimetric readings have failed due to a failed input from blowdown flow.

- The station air compressors had multiple problems: on August 9, the "D" compressor had a blown gasket on the top of the intercooler; on August 20, the "D" compressor inner cooler relief lifted too much to stay in service; on August 20, the operators noted that the "A" compressor was in lead but only half loads, the "C" compressor trips on high discharge pressure and the "D"

compressor had a stuck ERCW rotometer/or flow blockage to the compressor; when released from clearance on August 22, there was no ERCW flow to the "D" compressor; on August 23, the "D" compressor was removed from service because its intercooler relief valve was lifting; on August 23, when "D" compressor was placed back in service, the post maintenance test (PMT) was unsuccessful because air was blowing out the side plate on the compressor; on August 24, a work request was written on the "C" control air prefilter due to high filter differential pressure (DP); and on August 24, operators tagged out the "D" compressor.

- On August 13, Unit 2 rods auto stepped "out" with no signal (8:00, 8:05, 11:04, and 11:09 a.m., and 12:11 p.m.). On August 16, Unit 1 rods stepped "in" for no apparent reason. On August 17, Unit 2 rods stepped "in" for no apparent reason at 2:03 p.m., and 3:07 p.m. On August 18, Unit 1 rods stepped "in" for no apparent reason.

- On August 23, Unit 2 loop calculation processor (LCP) card failed. Shortly after the card failure, a steam dump failed open when the steam dumps were placed in the "pressure mode". On September 10, a Unit 1 LCP card failed. A replacement card was not available and the unit had to remain in a degraded condition until a replacement card could be found.

- The 161 and 500 kv switchyard cable tunnels were flooded with several inches of water. The permanent pumps were not operable and the temporary pump had been removed.

- On Unit 2, 3 of 4 steam generator blowdown sample valves will not open.

Several of the problem areas listed above were also included in IR 50-327,328/96-08, Section M2.3, Equipment Material Condition and Reliability Issues, and included the EDG air starting system, the station air compressors, a protection set card and the containment chillers.

c. Conclusions

The listed examples indicate weaknesses in plant material condition. The repetitive problems caused added operator burden (work-arounds). Such as: increased monitoring of the EDG starting air receivers; manual operation of the EDG starting air compressors; and special monitoring of the CRDM cooling supply valves. The multiple failures impacted maintenance resources in correcting the problems and operations resources for switching and tagging and equipment status control. Examples such as the stuck RCP seal leakoff detectors, automatic rod stepping, and failed LCP cards impacted day to day operations. These are indicative of weaknesses in maintenance and engineering support.

M2.4 Review of EDG Governor Booster Cylinder Corrective Actions

a. Inspection Scope (40500)

The inspector reviewed the corrective actions for a previous EDG governor booster cylinder failure to determine if corrective actions were adequate.

b. Observations and Findings

NRC Inspection Report 50-327,328/96-02 described the circumstances of a failure of the EDG 1A1 governor booster servomotor. The booster servomotor was replaced and the failed unit was sent to the vendor for failure analysis. The licensee also evaluated the failure at their own independent laboratory.

The licensee determined that no PM existed for replacing governor booster servomotors. The governor booster servomotor which failed had been in service for approximately 20 years. A 12-year PM was submitted by the technical support engineer to establish a governor booster servomotor replacement interval.

The inspector reviewed the failure analyses performed by the vendor and the TVA lab. The vendor concluded that the booster had exceeded its end of life and the booster piston seals were worn due to normal aging. Greasy debris and rust particles were also observed to be restricting the cylinder air ports. The inspector discussed the failure analyses with technical support personnel and determined that the rust particles were probably due to system piping corrosion which occurred prior to the use of system air dryers. Oil side leakage past the cylinder seals could have contributed to the air port fouling. The inspector verified by plant walkdowns that the air lines to the governor servomotors were upstream of the air line lubricators. The inspector determined that the licensee had evaluated the findings of the two failure analyses reports and was taking action to address these findings.

c. Conclusions

The licensee's corrective actions for the EDG governor booster servomotor failure was satisfactory.

**M3 Maintenance Procedures and Documentation**

M3.1 Review of Steam Generator Documentation

a. Inspection Scope (73753)

The inspector reviewed procedures, programs, and records associated with the condition of the Sequoyah Steam Generators (SGs) to determine if the licensee met FSAR commitments. (This review was the completion of an inspection initiated July 8-12, 1996, and documented in Inspection Report 50-327,328/96-08, Paragraphs M2.2 and M6.1)

b. Observations and Findings

Two SG areas which have historically contained tubing materials with high residual tensile stresses, and therefore susceptible to stress-related cracking problems, are the tight radius bends in rows 1 and 2 of the tube bundle, and the inside surface of the tubing where it was explosively expanded against the tube sheet. The licensee has attempted to reduce, or eliminate, the tensile stresses in these areas of the SGs by: heat treating (stress relieving) the tubing in the tight radius bends; and by peening the inside surface of the tubing in the tube sheet, to change the surface condition of the material from residual tensile stresses to residual compressive stresses.

The inspector selected the heat treatment of the Unit 2 SGs as a sample of this program to review. The review included the Westinghouse Field Service Procedure STD-FP-1993-6558, Rev 1, dated 4/28/94, "Sequoyah Unit 2 (TEN) Model 51 U-bend Heat Treatment Field Procedure" and individual tube heat treatment records for the work done.

The inspector also reviewed material heat numbers and subsequently the chemistry and physical properties of the Unit 2 SGs tubes which have been plugged.

c. Conclusions

Steam Generator records indicated that the licensee had implemented a comprehensive program to minimize stress-related degradation of SG tubes.

**M6 Maintenance Organization and Administration**

M6.1 Management Involvement in the Steam Generator Program

a. Inspection Scope (73753)

The inspector reviewed documentation and held discussions with licensee personnel concerning management involvement with the SG program.

b. Observations and Findings

The inspector reviewed the current five-year plan for SG inspection and maintenance. During this review the licensee discussed their plans for requesting licensing approval for the repair of degraded SG tubes by the use of laser-welded sleeving. This repair method will also be used as a contingency method for recovery of previously plugged tubes.

A discussion was held with licensee engineering personnel concerning the fact that SG management is currently working with a 5% plugging limit on the SGs. The explanation offered was that in the past, TVA had not contracted for a more rigorous accident analysis to justify a higher plugging limit. The licensee went on to explain that TVA had recently changed nuclear fuel vendors, and as a part of the analysis of the new

fuel, TVA had requested an accident analysis which would support a 15% plugging limit on the SGs.

The inspector, and licensee SG management personnel, also discussed the licensee's rationale for not lowering $T_{Hot}$ to protect the SGs. The major reason for not reducing $T_{Hot}$ appears to be the significant revenue loss from the resulting power reduction.

c. Conclusions

The licensee's SG organization has done a very good job of reviewing their inspection and repair options, and soliciting plant and corporate management support for the options selected.

**M8 Miscellaneous Maintenance Issues**

M8.1 (Closed) Licensee Event Report (LER) 50-327/95014, "Failure to Properly Identify and Plug a Steam Generator (SG) Tube that was Determined to Exceed the Technical Specification Plugging Limit."

(Closed) Licensee Event Report (LER) 50-328/96002, "Failure to Properly Identify a Steam Generator (SG) Tube that may have Exceeded the Technical Specification Plugging Criteria."

The similarities between these two events is that the defects in question were caused by degradation mechanisms expected in these SGs, and that in each case, two independent analyses missed the defects.

The licensee's corrective action for LER 50-327/95014 included the addition of dented intersections with flaws to the performance data base used to train and qualify eddy current analysis. The corrective action for LER 50-328/96002 included the addition of Rows 1 and 2 U-bends with severe permeability variations in the performance data base, and an update to the Steam Generator Analysis Guidelines, to enhance permeability variation effects in the U-bend regions.

The inspector reviewed the August 1996, revision of the Steam Generator Analysis Guidelines and verified that permeability variation effects had been enhanced. The inspector also reviewed a demonstration of the licensee's performance data base, which included the Row 1 U-bend with severe permeability which had been the subject of LER 50-328/96002.

The problems identified in the LERs constituted two examples of licensee identified violations of the plant technical specification definitions for SG operability. The two LERs are considered to be two examples of one violation because the violation reported in LER 50-328/96002 had already occurred when the violation reported in LER 50-327/95014 was discovered, and the increased sensitivity to that type of problem led to the second discovery.

The TS violations described in the LERs meet the criteria for a licensee identified, non-cited violation, as described in Section VII.B.1 of the

NRC Enforcement Policy. This will be reported as NCV 50-327,328/96-09-04, "Failure to Identify Steam Generator Tube Defects Which Were in Excess of TS Plugging Limits."

## III. Engineering

### E1 Conduct of Engineering

E1.1 General Comments (37551)

During the inspection period, TVA finalized the reorganization of site staffing. Discussions with engineering indicated that the system engineering department/section was significantly affected. Seventeen of forty-nine positions were left unfilled/vacant. In addition, some engineers changed positions and responsibilities. Engineering plans to fill the positions as soon as appropriate personnel are identified.

### E2 Engineering Support of Facilities and Equipment

E2.1 Review of Licensee Evaluation of Potential for Incorrect Material Received From Vendor

a. Inspection Scope (37551)

On June 21, 1996, the licensee received a request for assistance letter relating to a 10 Code of Federal Regulations (CFR) Part 21 Evaluation for material received from Consolidated Power Supply. The material included 3/4" schedule 80 pipe which may not have been the type specified on the purchase order. The inspector reviewed the Part 21 information, PER SQ961874PER, which was written to evaluate the condition, and the corrective actions associated with the issue.

b. Observations and Findings

The initial licensee engineering evaluation for PER No. SQ961874PER was reviewed by Region II specialists during the week of July 8-12, 1996. The licensee stated they received a shipment of the suspect material under Contract Number P-95N2J-148011-000. The licensee determined that the material was used in different plant applications; however, the only technical concern for material received was associated with weld processes used if the material was not as specified in the contract. The licensee initially determined that no safety-related applications were involved in the use of the supplied material which involved welding. The Region II inspectors noted that the weld process used by the licensee may have been inappropriate for materials supplied and could result in cracking, breaking, or failure.

During this period, the inspector conducted additional review of the issue. The inspector met with licensee engineering personnel and discussed the concerns associated with potential welding applications.

Over the next two weeks, the licensee conducted additional testing of the materials received from the vendor. Testing of samples of piping from the five pieces received from the vendor under Contract Number P-95N2J-148011-000 determined the piping was as specified in the contract.

c. Conclusions

The inspector concluded that after identification of initial concerns based on the engineering evaluation for the Part 21 potential problem, the licensee took appropriate positive actions to determine the issue did not affect Sequoyah.

E2.2 Review of Status of Unit 1 Sample System

a. Inspection Scope (37551)

On August 2, 1996, the inspector conducted a walkdown of a temporary system installed on Unit 2 for drainage from steam generator blowdown sample drains in accordance with Temporary Alteration Control Form (TACF) 2-95-0012-043. The inspector reviewed the associated documentation supporting the TACF, and also conducted a walkdown of the Unit 1 hot sample room to evaluate the condition of the Sample System in this area.

b. Observations and Findings

The inspector verified the proper installation of the temporary alteration. During the review, the inspector noted that several sample valves on a panel associated with sampling of boron injection tanks (BIT), appeared to be in poor material condition. Past leakage was obvious on several of the valves based on coatings of boric acid. Further review of this issue determined that this portion of the sample system was not being used. The inspector noted that there was no documentation that abandoned this portion of the sample system. The system engineer wrote PER SQ962182PER for determination of whether these sampling lines need to be formally abandoned. The inspector noted that proper valve status control was being maintained for this portion of the sample system.

c. Conclusions

The inspector concluded that the temporary alteration in the Unit 2 hot sample sink room was installed in a satisfactory manner and the safety assessment justified the installation. However, the inspector noted that sample valves located in the Unit 1 hot sample room for the Safety Injection system were in poor material condition and presented potential housekeeping problems. In addition, this portion of the sample system was not formally abandoned. The poor material condition of the valves and the informal control of abandoned equipment were considered to be negative observations.

E2.3 Unit 1 Residual Heat Removal System (RHR) Gas Accumulation

a. Inspection Scope (37551)

The inspectors reviewed the results of the Unit 1 RHR gas accumulation data which the licensee calculated during the American Society of Mechanical Engineers (ASME) Section XI tests on August 29, 1996 (A-Train) and September 5, 1996 (B-Train). The inspectors compared the data with previous gas accumulation data and reviewed the licensee's corrective actions for the gas accumulation problem. Previous reviews of the RHR gas accumulation issue were discussed in IPs 50-327,328/95-04, 95-06, 95-12, 96-01, and 96-08 and in Licensee Event Report (LER) 50-327/95001.

b. Observations and Findings

In November 1995, the licensee added Tracking and Reporting of Open Items (TROI) Action Item Number 29 to PER No. SQ950029PER. That PER was the original PER, initiated in January 1995, which dealt with the RHR gas accumulation. Action Item 29 required the licensee to "Develop methodology for evaluating the gas void momentum effect on RHR injection piping loads. Determine relationship of the piping void size to pipe loading and establish maximum allowable void size based upon piping structural margins."

In January 1996, an independent contractor completed a study of the Sequoyah RHR gas accumulation issue. One of the long term actions from that study stated that if too much gas was present, it could interfere with or delay delivery of low pressure injection in accident conditions and that the limit (maximum gas accumulation volume) should be determined by TVA and Westinghouse Accident Analysis.

In March 1996, the licensee established 8 cubic feet as the maximum allowable void size in the RHR system. The decision to use 8 cubic feet as the limit was based upon the known gas volume in the RHR system at the time and not upon a formal engineering analysis of the structural limits of the RHR system. The licensee concluded that since 8 cubic feet was known not to cause water hammer damage to the RHR system that it was reasonable to use 8 cubic feet as the maximum allowed limit and thus close the TROI action 29 based upon that assumption. However, the closure of action item 29 stated that the void size of 8 cubic feet could not be relaxed.

On August 29, during an ASME Section XI test on the RHR 1A-A pump, the licensee calculated the gas volume to be 11.6 cubic feet. On August 30, 1996, in response to the identification of 11.6 cubic feet of gas, the licensee completed another engineering evaluation to determine the maximum allowable gas accumulation. The new evaluation referred to the previous 8 cubic feet limit as an administrative limit and revised the gas accumulation limit to 15 cubic feet. Again, the evaluation was based upon the known history of gas build up rate and not upon a formal engineering evaluation. The evaluation stated that the average gas

accumulation rate since January 1996, has been approximately 4 cubic feet per quarter. The evaluation assumed that 4 cubic feet was indicative of the accumulation rate in the past and that as much as 24 cubic feet of gas (4 cubic feet per quarter x 6 quarters per operating cycle) had been present, prior to the current practice of quarterly venting, during previous quarterly Section XI pump testing and had not resulted in water hammer damage. The licensee concluded that since 15 cubic feet of total gas accumulation was significantly less than the total volume of gas expected to accumulate for a full fuel cycle (24 cubic feet), the associated pipe movements would not be sufficient to cause pipe support failures or challenge the integrity of the piping pressure boundary.

On September 5, 1996, during a Section XI test on the RHR 1B-B pump, the gas volume was determined to be 13.8 cubic feet. Following the identification of 13.8 cubic feet of gas, the licensee reevaluated the limit of 15 cubic feet which had been established on August 30. On September 6, using the same methodology as was used on August 30, the licensee reestablished the maximum gas void limit at 22 cubic feet.

It should be noted that the gas accumulation calculations on August 29 and September 5, were performed after the RHR system had been vented and that the licensee did not measure the volume of the vented gas. Therefore, the calculated gas accumulation of 11.6 and 13.8 cubic feet represented the "as-left" gas accumulation in the system.

As discussed in Inspection Report 50-327, 328/96-08, the licensee plans to install a continuous venting modification during the next two refueling outages.

c. <u>Conclusions</u>

The inspectors were unable to conclude whether the licensee's method of determining the maximum allowable RHR gas accumulation, to preclude water hammer damage, was acceptable. Pending the resolution of this issue, this item is identified as URI 50-327, 328/96-09-05, Determine Whether the Licensee's Method of Determining the Maximum Permissible RHR Gas Void Size is Acceptable.

The inspectors concluded that licensee's practice of venting the RHR system prior to calculating the volume of gas in the system did not provide an accurate representation of the total amount of gas in the RHR system.

E2.4 <u>Unit 2 Core Flux Tilt</u>

a. <u>Inspection Scope (37551)</u>

During the inspection period the inspectors were informed of a Unit 2 core flux tilt and of potential plans to reduce axial flux difference (AFD) limits if subsequent flux maps identified additional reductions in margins.

b. Observations and Findings

After noting the flux tilt problem in Unit 2, the inspectors discussed the condition with site reactor engineering personnel. Engineering noted that the unit 2 core tilt had developed following the refueling outage in May 1996 and that the tilt had increased to almost 3%. A specific reason for the tilt could not be identified. At the completion of the inspection period the tilt had decreased to approximately 1.7%. The inspectors discussed the tilt condition with NRC Region II and headquarters personnel.

Subsequent discussions with control room operators noted that some of the operators had not been aware of the tilt condition until the AFD limits had been reduced. The inspectors noted that the control room indications such as delta T and Tave did not identify a tilt condition. In addition, the inspectors noted that the computer printout for tilt, did not indicate a tilt condition. Discussions with engineering indicated that following a flux map, the nuclear instrument inputs are normalized which eliminates the actual tilt indication. Discussions with the region and with other utilities noted that this was a standard practice.

c. Conclusions

It was determined that while the tilt condition was somewhat unusual, the licensee was properly monitoring the condition and had taken appropriate actions. However, engineering did not clearly communicate, to operations personnel or to the resident inspectors, the fact that a tilt condition existed in the Unit 2 core for an extended period of time following discovery. Although not reportable or safety significant, the lack of prompt communication is being noted as a negative observation.

## E4 Engineering Staff Knowledge and Performance

E4.1 Improper Emergency Diesel Generator Starting Air System Operation

a. Inspection Scope (37551)

The inspectors reviewed various documents and historical records to determine why the EDG starting air compressors were causing their relief valves to lift and causing the low pressure alarms to alarm. The documents included the control room logs, EDG starting air system corrective maintenance history, EDG design basis document, FSAR section containing the EDG starting air system, and the operator rounds logs. In addition, the inspectors interviewed the system engineers, auxiliary operators, and control room operators and observed system operation in manual and in automatic.

b. Observations and Findings

During the inspection period, the inspectors noted that the control room logs were documenting instances when the EDG starting air compressors were found with their relief valves lifting or when the low pressure alarms were in alarm. In addition, while observing outside AUO duties, the inspector observed the 2-B-2 EDG staring air receiver relief valve lifting. The receiver tank pressure was at approximately 343 psig and the compressor was still running although the normal system operating pressure band is 250-300 psig.

The inspectors discussed the improper operation of the EDG starting air compressor control circuitry with the system engineering technical support staff. The engineers stated that the root cause of the compressor misoperation was two fold: (1) operations was cycling the control switches when routinely (per shift) blowing down the air lines, and (2) due to the compressor dryer timer which could cause the compressor to run for up to 5 minutes after reaching shutoff pressure. Corrective actions were already in place for eliminating the air line blowdown requirement and the dryer timer issue was under review.

The inspectors observed actual operation of the air compressors and noted that it took approximately 20 minutes to increase system pressure from 270 psig to 300 psig and concluded that an additional 5 minutes would not have caused the pressure to increase to the relief valve setpoints. The inspectors then interviewed approximately 10 AUOs and a few control room operators and concluded that blowing down the air lines almost never caused the compressors to start unless already at the low pressure automatic start setpoint.

A detailed review of the control room logs noted that various relief valves had been found lifting on July 23, August 1 and 3, twice on August 23, and September 8, 9 and 10. In addition, the low pressure alarm was noted on August 4 and September 10. The inspector noted that the control room logs did not identify which specific valve was lifting and it appeared that system engineering was not aware that the receiver tank/system relief valves were lifting on occasion. It appeared that the engineers had assumed that only the compressor reliefs had been lifting.

The inspectors reviewed the corrective maintenance history for the compressor control switches. All of the switches had been replaced (modification) in late 1993 due to previous failures. Following replacement there were five recalibrations due to setpoint drift and eight replacements. In two cases, switches replaced in 1995, failed again in 1996 and in one case, a switch replaced on August 1, failed on August 3 and again on September 9. It was also noted that the switch problems were being encountered only during summer months.

After additional relief valve lift problems in September and open discussions with operations during the Plan of the Day meeting, engineering determined that the control switches were sticking due to

being temperature sensitive and plans were under development to replace the faulty switches.

c. Conclusions

The inspectors concluded that the licensee's efforts to resolve the faulty EDG starting air compressor control switch problem to be inadequate and untimely. The failure to promptly identify and correct conditions adverse to quality, is a violation of the licensee's corrective action program as required by 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, and as implemented by SSP-3.4 (VIO 50-327, 328/96-09-06).

In addition, the root cause determination for the initial failures was also considered to be inadequate and is considered to be a weakness. This ultimately led to multiple challenges to starting air system integrity (reliefs lifting).

## E.7 Quality Assurance in Engineering Activities

### E7.1 Updated Final Safety Analysis Report (UFSAR) Review

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

# IV. Plant Support

### F1.1 Review of Transient Fire Loading (TFL) Conditions

a. Inspection Scope (71750)

During the week of July 8 - 12, 1996, an NRC inspector questioned a condition associated with a TFL Permit TFL-95-0254 which was issued for the storage of 1500 pounds of cloth/rubber/plastic radiation protection clothing on Elevation 690 between column lines A4 and A6 in the Auxiliary Building. After the issue was identified, the licensee wrote PER SQ961962PER on July 12, 1996. During this period, the inspector reviewed the licensee's interim actions associated with the issue.

b. Observations and Findings

On July 30, 1996, the inspector reviewed the status of the licensee's interim actions. He conducted a tour of the area in the Auxiliary Building and noted that radiation protection clothing was still being

stored in this location. He also noted Permit TFL-95-0254 dated November 14, 1995, was still posted in the area. After the tour, the inspector questioned the licensee about the observed conditions, and requested appropriate justification for the transient fire loading condition. On July 31, 1996, after additional review by licensee engineering personnel, the licensee determined that the location being used to store the radiation protection clothing had been included under a deviation for compliance with 10 CFR 50, Appendix R, as a low combustible area. Although a portion of the clothing had been removed after July 12, the licensee had not initiated a new transient fire load permit to justify the observed condition on July 30. The licensee took immediate action to remove the remaining radiation protective clothing. The inspector verified that remaining protective clothing was removed from the Auxiliary Building area.

c. Conclusions

The inspector concluded the licensee did not take adequate immediate corrective actions for this transient fire load issue identified during the week of July 8 - 12, 1996. Appropriate corrective action was only taken after the NRC commenced additional review of the issue on July 30, 1996. This issue will be further dispositioned as part of a special inspection documented in Inspection Report 50-327, 328/96-10.

## V. Management Meetings

### X1 Exit Meeting Summary

The resident inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on September 17, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials would be considered proprietary. No proprietary information was identified.

## PARTIAL LIST OF PERSONS CONTACTED

Licensee

*Adney, R., Site Vice President
Brock, D., Maintenance Manager
Bryant, L., Outage Manager
*Burzynski, M., Engineering & Materials Manager
Clift, D., Planning and Technical Manager
Driscoll, D., Training Manager
*Fecht, M., Nuclear Assurance & Licensing Manager
Fink, F., Business and Work Performance Manager
*Flippo, T., Site Support Manager

*Kent, C., Radcon/Chemistry Manager
*Lagergren, B., Acting Operations Manager
*Meade, K., Compliance Manager
Poage, L., Site Quality Assurance Manager
*Rausch, R. Maintenance and Modifications Manager
Reynolds, J., Acting Operations Superintendent
Robertson, J., Independent Analysis Manager
*Rupert, J., Engineering and Support Services Manager
*Shell, R., Site Licensing Manager
*Skarzinski, M., Technical Support Manager
Smith, J., Regulatory Licensing Manager
*Summy, J., Assistant Plant Manager
Symonds, J. Modifications Manager

* Attended exit interview

## INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 40500: Effectiveness of Licensee Controls In Identifying, Resolving, & Preventing Problems
IP 61726: Surveillance Observations
IP 62703: Maintenance Observations
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 73753: Inservice Inspection

## ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| Type | Item Number | Status | Description and References |
|---|---|---|---|
| URI | 50-327,328/96-09-01 | Open | Determine Whether TS 3.3.1.1 Allows One Pressurizer Pressure Channel to Be Bypassed at the Same Time that a Second Pressurizer Channel is Tripped (Section O2.2). |
| NCV | 50-327/96-09-02 | Open/ Closed | Inoperable "A" Train of EGTS for 2 Hours and 43 Minutes Due to Operator Error (Section O3.2). |
| IFI | 50-327, 328/96-09-03 | Open | Review Corrective Actions Related to ERCW Check Valve Failure, PER SQ962283PER (Section M1.4). |
| NCV | 50-327, 328/96-09-04 | Open/ Closed | Failure to Identify Steam Generator Tube Defects Which Were in Excess of TS Plugging Limits (Section M8.2). |

| | | | |
|---|---|---|---|
| URI | 50-327, 328/96-09-05 | Open | Determine Whether the Licensee's Method of Determining the Maximum Permissible RHR Gas Void Size is Acceptable (Section E2.3). |
| VIO | 50-327, 328/96-09-06 | Open | Inadequate and Untimely Corrective Actions Associated With the Resolution of the EDG Starting Air Compressor Switch Failures (Section E4.1). |

Closed

| Type | Item Number | Status | Description and References |
|---|---|---|---|
| LER | 50-327/95014 | Closed | Failure to Properly Identify and Plug a Steam Generator (SG) Tube that was Determined to Exceed the Technical Specification Plugging Limit (Section M8.1). |
| LER | 50-328/96002 | Closed | Failure to Properly Identify a Steam Generator (SG) Tube that may have Exceeded the Technical Specification Plugging Criteria (Section 8.1). |

## LIST OF ACRONYMS USED

AFD - Axial Flux Difference
ASME - American Society of Mechanical Engineers
ASOS - Assistant Shift Operations Supervisor
AUO - Assistant Unit Operator
BIT - Boron Injection Tank
CCW - Condenser Cooling Water
CFR - Code of Federal Regulations
CRDM - Control Rod Drive Mechanism
EDG - Emergency Diesel Generator
EGTS - Emergency Gas Treatment System
ERCW - Essential Raw Cooling Water
FSAR - Final Safety Analysis Report
ICS - Integrated Control System
IFI - Inspector Followup Item
IP - Inspection Report
GPM - Gallons Per Minute
KV - Kilo-Volt
LCP - Loop Calculation Processor
LER - Licensee Event Report
MCR - Main Control Room
MI - Maintenance Instruction
M&TE - Measuring and Test Equipment

| | | |
|---|---|---|
| MWT | - | Megawatt-Thermal |
| NCV | - | Non-Cited Violation |
| NRC | - | Nuclear Regulatory Commission |
| NRR | - | Nuclear Reactor Regulation |
| PER | - | Problem Evaluation Report |
| PM | - | Preventive Maintenance |
| PMT | - | Post Maintenance Testing |
| PSIG | - | Pounds Per Square Inch Gauge |
| PZR | - | Pressurizer |
| RCS | - | Reactor Coolant System |
| RHR | - | Residual Heat Removal |
| RO | - | Reactor Operator |
| RP&C | - | Radiological Protection & Chemistry |
| SG | - | Steam Generator |
| SI | - | Surveillance Instruction |
| SRO | - | Senior Reactor Operator |
| SSP | - | Site Standard Practice |
| TACF | - | Temporary Alteration Change Form |
| TFL | - | Transient Fire Load |
| T-HOT | - | Temperature of the Primary Hot Leg |
| TROI | - | Tracking and Reporting of Open Items |
| TS | - | Technical Specifications |
| TSIR | - | Technical Support Investigation Request |
| TVA | - | Tennessee Valley Authority |
| UFSAR | - | Updated Final Safety Analysis Report |
| URI | - | Unresolved Item |
| WO | - | Work Order |
| WR | - | Work Request |