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

Report Nos.: 50-327/92-22 and 50-328/92-22

Licensee: Tennessee Valley Authority
6N 38A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

Docket Nos.: 50-327 and 50-328 License Nos.: DPR-77 and DPR-79

Facility Name: Sequoyah Units 1 and 2

Inspection Conducted: July 5 through August 1, 1992

Lead Inspector: Paul J. Kellogg for 8/12/92
W. E. Holland, Senior Resident Inspector Date Signed

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

Approved by: Paul J. Kellogg 8/12/92
Paul J. Kellogg, Chief, Section 4A Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant operations, plant maintenance, plant surveillance, evaluation of licensee self-assessment capability, licensee event report closeout, and followup on previous inspection findings. During the performance of this inspection, the resident inspectors conducted several reviews of the licensee's backshift or weekend operations.

Results:

In the Maintenance/Surveillance functional area, reviews were conducted in the areas of predictive maintenance, equipment failure trending, maintenance procedure quality and upgrades, maintenance backlog management, and maintenance training. In addition, reviews of items or issues which would allow for an evaluation of current plant material condition were conducted. One area, involving planning and control of work, appeared to be working very well with weekly schedule adherence and accomplishment of more work items per unit of time trending up. Also, the work order priority process was functioning well. Other areas, which appeared to have very good programs

included reliability centered maintenance and predictive maintenance; however, the latter program was not extensively used on safety-related ASME Section XI components. Also, the equipment failure trending program was considered to be good. Procedure quality was good in many areas; however, additional work was needed to complete procedure upgrades and convert to more user friendly PM instructions in the I&C and Electrical areas. Maintenance training appeared to be focused on apprentice craft and future training was being focused at maintenance supervision. Assessment reviews of department functional elements were being accomplished. Finally, plant material condition was identified as an area which had received management attention in several areas during the Cycle 5 outages; however, was lacking in other areas which required additional management focus (paragraph 4.a.).

In the Maintenance/Surveillance functional area, a violation was identified for failure to follow procedural requirements. This lack of procedural adherence resulted in poor housekeeping/cleanliness controls which affected the operability of the Unit 2 TDAFW pump (paragraph 4.b.).

In the Maintenance/Surveillance functional area, a surveillance program review concluded that the overall surveillance program was adequate. However, some problems identified by the licensee indicated weaknesses in the areas of personnel accountability, implementation of corrective actions once surveillance deficiencies are identified, and craft attention to detail (paragraph 5).

In the Maintenance/Surveillance functional area, a violation was identified for failure to follow procedural requirements. This lack of procedural adherence resulted in potential operation of Unit 2 in a condition outside of its design basis (paragraph 6.e.).

In the Safety-Assessment/Quality Verification functional area, a non-cited violation was identified for failure to implement effective corrective actions (paragraph 7.a.).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*J. Bynum, Vice President, Nuclear Operations
*J. Wilson, Site Vice President
R. Beecken, Plant Manager
*L. Bryant, Maintenance Manager
*M. Cooper, Site Licensing Manager
*T. Flippo, Site Quality Assurance Manager
*J. Gates, Technical Support Manager
C. Kent, Radiological Control Manager
M. Lorek, Operations Superintendent
P. Lydon, Operations Manager
*R. Rausch, Modifications Manager
J. Smith, Regulatory Licensing Manager
*R. Thompson, Compliance Licensing Manager
*P. Trudel, Nuclear Engineering Manager
*J. Ward, Engineering and Modifications Manager
N. Welch, Unit Manager

NRC Employees

B. Wilson, Chief, DRP Branch 4
P. Kellogg Chief, DRP Section 4A

*Attended exit interview.

Other licensee employees contacted included control room operators, shift technical advisors, shift supervisors and other plant personnel.

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

On July 27, 1992, J. P. Stohr, Director, Division of Radiation Safety and Safeguards, Region II, NRC, visited the Sequoyah site. Mr. Stohr attended a plan of the day meeting, met with various management personnel to discuss items of mutual interest, and toured the facility with the resident inspectors.

2. Plant Status

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

Unit 2 began the inspection period at approximately full power. The unit operated at approximately full power for the duration of the inspection period.

3. Operational Safety Verification (71707)

a. Daily Inspections

The inspectors conducted daily inspections in the following areas: control room staffing, access, and operator behavior; operator adherence to approved procedures, TS, and LCOs; examination of panels containing instrumentation and other reactor protection system elements to determine that required channels are operable; and review of control room operator logs, operating orders, plant deviation reports, tagout logs, temporary modification logs, and tags on components to verify compliance with approved procedures. The inspectors also routinely accompanied plant management on plant tours and observed the effectiveness of management's influence on activities being performed by plant personnel.

During this period, the inspectors held additional discussions with operations department personnel and supervision with regard to the status of operational procedures upgrades and quality of current procedures. The inspectors determined that the operations procedures writers group was staffed with 6 people (3 SRO qualified, 2 RO qualified and 2 experienced contractors). The inspectors noted that one SRO procedure writer had recently returned to shift work. This staffing was considered by licensee personnel to be the minimum necessary to complete the upgrades and perform day-to-day reviews and changes. The inspectors were informed that approximately 60% of the SOIs had been upgraded and that the GOIs were currently being reviewed for upgrade. Discussions with several operators indicated that some improvements have been noted and that the overall current procedure quality was adequate. The licensee indicated that future improvements were warranted; however, actual implementation of additional upgrades would be consistent with other planned site improvements, including manpower and budget considerations.

b. Weekly Inspections

The inspectors conducted weekly inspections in the following areas: operability verification of selected ESF systems by valve alignment, breaker positions, condition of equipment or component, and operability of instrumentation and support items essential to system actuation or performance. Plant tours were conducted which included observation of general plant/equipment conditions, fire protection and preventative measures, control of activities in progress, radiation protection controls, missile hazards, and plant housekeeping conditions/cleanliness.

(1) During the latter part of this period, the inspectors conducted walkdowns of safety-related pump and heat exchanger rooms. During the walkdowns, the inspectors determined that all were accessible without having to enter

a contaminated zones with the exception of RHR Pump Room 2B-B, and the RHR and Containment Spray Heat Exchanger Rooms for Unit 2. Licensee efforts have improved the overall radiological condition of the safety-related pumps, and subsequently increased accessibility for operators. Further attention to the reduction of the contaminated areas is warranted, particularly in the area of safety-related pump motors. To assist their efforts, the licensee has designated the 2A-A SI pump room as a "model" area for comparison purposes. In this room, the licensee has demonstrated the ability to reduce the contamination of the pump rooms and to provide better access for operators to the safety-related equipment. Other contaminated areas in the plant have decreased since the end of the Unit 2 Cycle 5 refueling outage. Since the end of the outage, the contaminated area has decreased from approximately 6.0% to the current level of 4.5 %. Continued progress in this area is indicative of managements commitment to maintain contaminated areas to a minimum.

(2) On July 23, the inspector identified the following material conditions relating to the EDGs: Several junction boxes were missing access port covers exposing electrical wiring; screws missing in junction boxes; conduit end plug not installed on a thermocouple lead; breaks in several small conduits; and split rubber coatings on conduit. All of the above equipment was near or under the area of the EDGs intake and exhaust which has previously experienced some intrusion of rainwater due to floor seal leakage. The inspectors also noted an increased amount of oil leakage in general on the engines and support equipment. Several lube oil system leaks were being collected with catch basins; however, no WRs were identified on the equipment. The inspector informed operations on the discrepancies. WRs were initiated as appropriate.

c. Biweekly Inspections

The inspectors conducted biweekly inspections in the following areas: verification review and walkdown of safety-related tagouts in effect; review of the sampling program (e.g., primary and secondary coolant samples, boric acid tank samples, plant liquid and gaseous samples); observation of control room shift turnover; review of implementation and use of the plant corrective action program; verification of selected portions of containment isolation lineups; and verification that notices to workers are posted as required by 10 CFR 19.

d. Other Inspection Activities

Inspection areas included the turbine building, diesel generator building, protected area yard, control room, vital 6.9 KV shutdown board rooms, 480 V breaker and battery rooms, and auxiliary building areas including all accessible safety-related pump and heat exchanger rooms. RCS leak rates were reviewed to ensure that detected or suspected leakage from the system was recorded, investigated, and evaluated; and that appropriate actions were taken, if required. The inspectors routinely independently calculated RCS leak rates using the NRC RCS leak rate computer program specifically formatted for Sequoyah. RWPs were reviewed, and specific work activities were monitored to assure they were being accomplished per the RWPs. Selected radiation protection instruments were periodically checked, and equipment operability and calibration frequencies were verified.

On July 28, 1992, a control room (CR) reactor operator (RO) mistakenly blocked both CR ventilation radiation monitors (0-RM-90-125,126). Operations had requested a filter change to the area radiation monitors (RM-90-105) due to several instrument malfunction alarms. These filter changes are typically done without a procedure. The RO mistakenly assumed that one CR ventilation system radiation monitor needed to be blocked in conjunction with the CR area radiation monitor. The RO also isolated the other CR ventilation system radiation monitor, apparently due to his unfamiliarity with the system operation. The inadvertent isolation was realized and both radiation monitors were unblocked after 12 minutes. Blocking of both control room radiation monitors requires the licensee to enter TS 3.3.3.1, Table 3.3-6, Action 29, which requires within one hour the initiation of CR emergency ventilation in the recirculation mode. The licensee initiated SQPER920264 to investigate this event. The inspectors consider this to be an example of inattention to detail in that the RO was unfamiliar with CR ventilation system operation during this evolution.

e. Physical Security Program Insp .tions

In the course of the monthly activities, the inspectors included a review of the licensee's physical security program. The performance of variou: shifts of the security force was observed in the conduct of daily activities to include: protected and vital area access controls; searching of personnel and packages; escorting of visitors; badge issuance and retrieval; and patrols and compensatory posts. In addition, the inspectors observed protected area lighting, and protected and vital areas barrier integrity.

f. Licensee NRC Notifications

(1) On July 16, the licensee made a call to the NRC as required by 10 CFR 50.72 concerning the discovery of a condition which placed both Sequoyah operating units outside of their design basis. The licensee determined that a mass energy release during a double-ended guillotine main steam line

break in the main steam valve vaults could exceed the original structural design values of the valve vaults by a factor of four, which could compromise the valve vaults and other safety-related equipment therein.

The licensee's engineering organization addressed the immediate operability issue with a Justification for Continued Operation (JCO) based on mechanistic piping stress evaluations which enabled the licensee to satisfy criteria per NRC Branch Technical Position MEB 3-1. This classification allowed the licensee to limit the postulated main steam line break inside the vaults to 1.0 ft^2 (.028 m^2) or less rather than analyzing for the original designed basis guillotine main steam line break. Utilizing the 1.0 ft^2 line break limit, the licensee concluded that the new mass energy release values would not challenge the structural integrity of the valve vault.

A conference call was held between the licensee and NRC Region II and headquarters personnel. Additional information was requested and subsequently received from the licensee to substantiate their JCO position. No immediate operability concerns were expressed by any of the parties on the call pending additional licensee and NRC reviews.

(2) On July 28, the licensee made a call to the NRC as required by 10 CFR 50.72 concerning the operation of Unit 2 in a condition potentially outside of the design basis of the plant. The call resulted from the licensee recognizing the potential issue during an Incident Investigation (II) involving the 2B-3 RHR pump. The II was initiated when a problem was discovered on July 17, in which a wiring discrepancy on flow switch 2-FS-74-24 affected miniflow valve operation of the 2B-B RHR pump during system testing. The wiring discrepancy was determined to be in place since July 1 and caused the pump recirculation valve to repeatedly cycle during testing conducted on July 17. Subsequent analysis of the cycling phenomenon identified that the recirculation valve could fail and ultimately result in failure of the RHR pump. Second party configuration verification and functional testing failed to identify the wiring problem. This issue is further discussed in paragraph 6.d of this Inspection Report.

Within the areas inspected, no violations were identified.

4. Maintenance Inspections (62703 & 42700)

a. During this inspection period, the inspectors conducted a review of the implementation of licensee maintenance programs which included, predictive maintenance, equipment failure trending, maintenance procedure quality and upgrades, maintenance backlog management, and maintenance training activities. In addition, the inspectors reviewed items or issues which would allow for an evaluation of current plant material condition.

(1) Plant Material Condition - The inspectors conducted a review of past events for the last 12 months at Sequoyah and determined that plant material condition has generally improved in some areas; however, many other areas need continuing management attention to return plant components to routine maintenance condition. Some of the areas that have been improved over the past year include (1) a new control room annunciation system and the reduction in the number of lit annunciators, (2) installation of new 5th, 6th, and 7th point feedwater heaters in the plant secondary for both units, (3) AFW system modifications to allow for greater recirculation flow during normal system operation, (4) changeout of the third component cooling water heat exchanger, (5) Diesel Generator air system upgrades, (6) CRDM motor generator set refurbishment, and (7) continuation of a protective coatings application on the different levels in the auxiliary building. Several areas noted to be in need of additional attention were (1) heat trace for boric acid flowpaths in the CVCS, (2) room and space coolers used in safety-related applications, (3) secondary system level control valves, (4) radiation monitoring equipment, (5) remote operators for Grinnell valves, (6) Auxiliary Building drain lines, and (7) fire protection component deficiencies requiring routine use of fire watches throughout the plant during the last 18 months. The inspectors also noted that the last seven reactor trip events which occurred over the last 12 months were associated with plant component failures.

(2) Predictive Maintenance Programs - The inspectors conducted a review of the licensee's implementation of predictive maintenance which included vibration monitoring, oil analysis, and thermography. Discussions were held with maintenance engineering personnel involved in the program. The inspectors determined that vibration analysis had been implemented for at least 2 years and that good equipment was being used to allow for proper diagnostics of problems. The inspectors also noted that most of the focus of the maintenance group was on components or pumps that operate continuously and other problem components. The ASME Section XI testing was conducted by operations personnel as a part of the routine surveillance program. The oil analysis

program has been fully implemented for at least 12 months and appeared to be well controlled with regard to sample identification and testing. However, implementation of oil analysis and testing was not effective in precluding the event discussed in paragraph 4.b. The thermography program had been in existence for approximately 6 months and was used on transformers and raw service water heat exchangers.

The licensee had also instituted a Reliability Centered Maintenance Program in 1990 and was continuing to develop the system analysis packages in accordance with a schedule that projected analysis completion of 84 systems by September 1994. The inspectors noted that 18 system evaluation packages had been completed, of which the majority were safety systems. The licensee was maintaining a close working relationship with industry organizations in the development of the program to satisfy projected requirements of the proposed maintenance rule. The inspectors considered that this program would have a positive impact on component reliability in the future.

The inspectors concluded that the licensee's reliability centered maintenance and predictive maintenance programs were being implemented in a good manner; however, the ASME Section XI testing was not providing the quality of information for some safety-related components that was provided by the vibrational monitoring equipment used by maintenance engineering personnel in their program.

(3) Equipment Failure Trending Program - The inspectors conducted a review of the licensee's process for trending of equipment/component failures. The program was clearly defined in administrative procedure and was discussed with licensee personnel during the period. The program uses two methods to identify adverse component trends. One method involves 2 or more failures of individual components within four years and the other method involves a failure of more than 3% of the same manufacturer/model number (and/or more than 5% of the same manufacturer) within a 1 year period. When adverse trends are identified and substantiated, a corrective action report is initiated to document the problem and provide for appropriate corrective actions. The inspectors considered that the program was well defined and had identified 166 trend evaluation reports for the second quarter of 1992; however, a review of one recent specific problem associated with leaking space coolers noted a condition where the program had not identified this adverse trend.

(4) Maintenance Procedure Quality - The inspectors conducted a review of the licensee's maintenance procedures and considered that the overall quality of the procedures was

good. Most of the mechanical maintenance procedures had been upgraded to the newest procedure writer's guide format; however, electrical maintenance had upgraded less that 50%. The instrumentation and control section generally had good procedures available to perform routine work; however, approximately 15% of their procedures were on administrative hold and non technical specification surveillance instructions for both I&C and electrical maintenance were in the process of being converted to more user friendly PM instructions. Licensee personnel indicated that current resources were available to complete the upgrades prior to the next refueling outage (April 1993).

(5) Maintenance Backlog - A review of the licensee's maintenance backlog was conducted during this period. The inspectors noted that both units had completed refueling outages within the past 7 months (Unit 1 - December 1991, Unit 2 - May 1992). The total non-outage corrective maintenance backlog was approximately 855 work orders for the plant. Also, total open work orders for preventative and other work was approximately 460. The licensee considered that non-outage workorder backlog was higher than desired; however, the totals were being well managed and trending down. The inspectors specifically noted that the planning activities were well coordinated and that the work control organization was increasing workload on the craft to optimum levels while the maintenance organization was consistently maintaining a weekly work order completion of greater than 90% of the scheduled completion rate. Close management attention was noted to be continuously focused in this area. The inspectors also reviewed the outage related work orders and noted that remaining outage related work orders at the end of the outage for the Unit 2 Cycle 5 refueling were significantly higher than the outage related work orders at the end of the Unit 1 Cycle 5 outage. The inspectors concluded, after discussions with licensee personnel, that this condition was based on licensee management's decision to reduce expenditures to meet the outage budget and to maintain schedule adherence for the Unit 2 Cycle 5 outage. These decisions were based on management review and evaluation of initial outage scope against overall outage and operational objectives, including safety, resource, schedule, and operational performance impacts.

(6) Maintenance Training Programs - A review of the licensee's training programs for the maintenance department indicated that TVA had started a mulit-phase apprentice program to train craft in the Mechanical, Electrical, and I&C areas. A training program for maintenance supervisors is scheduled to commence in the Fall 1992.

(7) Maintenance Self-Assessments - During this review the inspectors specifically questioned licensee management with regard to whether self assessments were conducted by the Maintenance Department. The inspectors were provided with Site Maintenance Management Directive (SMMD) 91-002-MMO, Revision 1. This directive required maintenance management and supervision to conduct periodic assessments of key facets of the maintenance program areas. The inspectors reviewed the directive and concluded that the assessment process would provide for meaningful evaluation of maintenance program elements in order to improve performance.

In summary, the inspectors concluded that the implementation of the maintenance programs that were reviewed were being accomplished in a good manner. One area, involving control of work, appeared to be working very well with weekly schedule adherence and accomplishment of more work items per unit of time trending up. Also, the work order planning and priority process was functioning well. Other areas, which appeared to have very good programs included reliability centered maintenance and predictive maintenance; however, the latter program was not extensively used on safety-related ASME Section XI components. Also, the equipment failure trending program was considered to be good. Procedure quality was good in many areas; however, additional work was needed to complete procedure upgrades and convert to more user friendly PM instructions in the I&C and Electrical areas. Maintenance training appeared to be focused on apprentice craft and future training was being focused on maintenance supervision. Self assessments of department functions were being accomplished. Finally, plant material condition was identified as an area which had received management attention in several areas during the Cycle 5 outages; however, was lacking in other areas which required additional management focus.

b. On July 26, the inspectors reviewed licensee maintenance activities on the Unit 2 TDAFW pump (WR C126671). Earlier, on July 24, at 12:50 CST, TS 3.7.1.2.a was entered to perform Section XI testing on the pump. During performance of the testing, a problem was identified with level swings in the turbine lube oil system. System engineering concluded that the problem was directly related to the use of a vapor space inhibitor (VSI) type oil which had previously replaced the original standard turbine oil (STO-1). As corrective action, the turbine oil was changed out to the STO-1 type and subsequent operation of the pump and oil system was satisfactory. A similar problem was identified on the Unit 1 TDAFW pump in May of 1992 and was discussed in detail in NRC Inspection Report 327, 328/92-15. In the previous inspection, the inspectors had questioned the continued use of VSI oil in the Unit 2 TDAFW; however, at that time, the licensee indicated that no evidence of oil leakage or abnormal swings during operation were apparent and concluded that changeout of the oil or sampling was not warranted. The inspector considered the licensee's decision not to sample or replace the Unit 2's AFW turbine oil upon identification of the Unit 1 problem was non-conservative.

Subsequent to the above activities, the licensee performed a new work order instruction as the PMT for the pump work and testing in order to provide increased assurance of pump operability. The PMT included running the pump, inducing an electrical trip from the control room, and restarting the pump after coastdown. During this process, the pump could not be restarted after it was tripped due to the governor valve not returning to the full open position. The inspector became aware of this problem early on July 26 and monitored licensee activities to troubleshoot the issue. The licensee repeated the condition several times, looked for potential binding points, and took voltage readings on the electrical control for the governor valve. Technical Support, Operations, and Nuclear Engineering were actively involved in the activities. Upon satisfactory results of the electrical testing, the licensee again focused on possible hydraulic or mechanical binding of the valve. An SOS observation that the governor valve movement appeared erratic when compared to previous experience with the valve's operation led personnel to identify that the valve was experiencing mechanical binding when the valve was near the closed position. The licensee concluded that an accumulation of debris from the ongoing floor recoatings project caused the abnormal operation of the valve. Minimal lubrication on a shaft support bushing may have also contributed to the problem. After cleaning and lubrication of the shaft bushing, the pump successfully passed the specified PMT. The pump was later declared operable at 6:24 p.m. EST on July 26.

The inspectors reviewed the licensee's procedural requirements with regard to this event. Site Standard practice 12.7, HOUSEKEEPING/TEMPORARY EQUIPMENT CONTROL, Revision 7, Section 3.1.1.B, states ,in part, that the foreman or work supervisor in charge of an activity shall ensure that proper cleanliness is maintained during and after completion of a work activity. In addition, Maintenance Instruction (MI) 10.14, APPLICATION REPAIR OF PROTECTIVE COATINGS IN THE REACTORS AND AUXILIARY BUILDINGS, Revision 24, Section 3.6, states, in part, that equipment that may be damaged by coating work activities shall be protected by covering, enclosing, or removal from the work area to ensure that no equipment degradation occurs. Contrary to the above, on or before July 24, 1992, modifications personnel failed to maintain adequate cleanliness control during floor recoating in the Turbine Driven Auxiliary Feedwater Pump room. This condition resulted in a failure of the pump to pass its required post-maintenance test and also a significant delay in returning the safety-related pump to operable status.

On July 31, the inspectors reviewed the status of the Unit 2 TDAFW pump and learned that the pump was declared inoperable on July 30, at 11:00 a.m. EST due to the identification that an epoxy coating had been applied to the mechanical linkage of the pump's governor valve. Some material was also identified on or around the shaft and seal mechanisms. After declaring the pump inoperable, cleaning of the linkages and shaft was performed. Other problems were encountered with the reassembly of the parts; however, the inspectors verified that the pump was later returned to operable status as of 6:05 p.m. EST on July 31.

The inspectors reviewed the licensee's procedural requirements with regard to this event. Maintenance Instruction (MI) 10.14, APPLICATION REPAIR OF PROTECTIVE COATINGS IN THE REACTORS AND AUXILIARY BUILDINGS, Revision 24, Section 3.8, states, in part, that precautions shall be taken to ensure that coating of components with moving parts are not compromised for their intended design function due to binding, resulting from coating material ie., mechanical linkage on the Diesel Generators. Contrary to the above, on July 29, 1992, operability of the Unit 2 Turbine Driven Auxiliary Feedwater Pump was compromised due to modifications personnel applying an epoxy coating to the mechanical linkages and other equipment necessary for normal operation of the pump governor valve.

These examples of failure to follow housekeeping and/or cleanliness requirements during modifications activities around safety-related components are identified as a violation for failure to follow procedure (VIO 328/92-22-01).

The inspectors concluded that housekeeping and management oversight of the work in progress for the above activities was poor. The identified conditions directly affected operability or the timely return to operable status of the Unit 2 TDAFW pump on two separate occasions.

Within the areas inspected, one violation was identified.

5. Surveillance Inspections (61726 & 42700)

During the reporting period, the inspectors reviewed various surveillance activities to assure compliance with the appropriate procedures and requirements. The inspection included a review of the following administrative procedures, surveillance instructions and observation of surveillances:

- SSP-8.1, Conduct of Testing, Rev. 3
- SSP-8.2, Surveillance Test Program, Rev. 0.
- 2-SI-OPS-082-007.0, Diesel Generator Operability Verification
- SI-102 M/M, Diesel Generator Monthly Mechanical Inspection
- SI-170.1, Periodic Calibration of Diesel Generator 1A-A

Personnel involved with the surveillances were knowledgeable of procedural acceptance criteria, and were cognizant of equipment operability status during the surveillance test performance. The licensee conducted the surveillances in compliance with the appropriate procedures and requirements. The inspectors did not identify any concerns during the performance of these surveillances.

The inspectors discussed and reviewed surveillance scheduling with licensee personnel. The inspectors noted that this area received high visibility from senior management during the plant manager's bi-weekly meeting. The inspectors performed a cursory review of LERs, QA audits, Incident Investigations, and other documentation, and did not identify any scheduling concerns. The inspectors also reviewed licensee corrective actions for recent surveillance problems. The inspectors identified LER 327/92-01 and LER 327/91-01 as an example of a weakness in implementation of corrective actions in response to a surveillance deficiency. These LERs are further discussed in paragraph 7.a of this Inspection Report.

The inspectors reviewed and discussed with the licensee a recent QA audit (QSQ-R-92-411) associated with surveillance testing. The audit identified an improvement in 1992 in the surveillance procedural adequacy area. However, a deterioration was noted in surveillance performance deficiencies, due to inattention to detail and failure to follow procedures. The inspectors also reviewed corrective actions in response to SCAR SQSCA910013, which was issued due to documentation errors and technical problems with surveillance instructions. Corrective actions in response to this SCAR include the establishment of a single point of contact for each department to review completed surveillance procedures. Personnel accountability has also been emphasized, and SI performance has been incorporated into personnel performance appraisals. Feedback to Operations has also been provided through monthly performance reports. Discussions with plant management indicate that these activities appear to be positive steps toward reducing surveillance instruction errors. Administrative errors and technical errors have decreased over the past six months.

The inspectors concluded that the overall surveillance program is adequate. However, the problems identified above indicate weaknesses in the areas of personnel accountability, implementation of corrective actions once surveillance deficiencies are identified, and craft attention to detail. The inspectors will continue to review the results of plant management's oversight to improve these areas of the surveillance program.

Within the areas inspected, no violations were identified.

6. Evaluation of Licensee Self-Assessment Capability (40500)

During this inspection period, selected reviews were conducted of the licensee's ongoing self-assessment programs in order to evaluate the effectiveness of these programs. The inspectors specifically focused on several of the licensee's incident investigations during the inspection period.

a. During the inspection period, the inspectors attended plant staff meetings in order to evaluate their effectiveness. The inspectors noted that plant management had recently rearranged the plant meeting formats and schedules to better support daily activities. The plan of the day meetings were being held each weekday at 7:00 a.m. with required attendance by all major departments. A plant manager's meeting was being held every Tuesday and Thursday at 9:00 a.m. to discuss topics including plant safety, incident investigation status, operations top ten work requests, temporary alteration status, licensing issues, etc. The meetings appear to be adequately organized to allow an accounting of the current plant status, work items planned and accomplished, and other special activities for the day. However, meeting effectiveness has not been evaluated due to the short time since implementation of the new schedules and format.

b. During this period, the inspectors evaluated the function of the licensee's Independent Safety Engineering (ISE) group. Reviews by ISE are required by TS 6.2.3 to examine plant operating characteristics, NRC issuances, industry advisories, LERs, and other sources which may indicate areas for improving plant safety. The onsite ISE group consists of four full-time engineers. This staff is supplemented by one corporate engineer which meets the personnel staffing requirements of the TS. Group experience, cross engineering discipline, and a variety of root cause and investigative training contribute to the qualifications of the ISE group.

Major functions the ISE group performs include review of industry information, surveillance of plant activities, and reviews of specific plant performance areas. Industry reviews and other information sources appear to be screened in an adequate manner. Sampled reports responding to specific actions assigned by the corporate NER office were complete and provided substantive recommendations. Of particular note was ISE report No. ISE-SQN-91-R02, Outage Nuclear Safety Review. This review resulted from a management request to evaluate the Unit 1 Cycle 5 refueling outage schedule and the plants overall performance with regard to recent industry concerns regarding outage risk management. The recommendations of the review lead to numerous specific improvements in activities related to outage risk management. Surveillance audits reviewed by the inspectors were detailed and provided useful recommendations to plant management. Interaction with QA during audit and surveillance functions was occurring on a limited basis to improve inspection/audit techniques of the group. The ISE manager indicated that increased involvement with QA is planned. Both self-initiated and plant management directed team reviews of specific performance areas were well performed. ISE response to management directives appeared to be good. The reviews were typically performance based and resulted in formal recommendations which were tracked on the licensee's action items list for resolution. In addition to the above activities, ISE has been actively involved in efforts to reduce human error related events. The ISE group supplemented the licensee's II process by providing an HPES trained team member for a majority of the IIs performed. ISE also reviews completed IIs for adequacy and safety implications.

The inspector attended a weekly screening meeting held by the site NER Manager which included ISE participation. Communications between NER and ISE appeared to be adequate; however, should improve due to proposed management changes for the two groups. The licensee also conducts quarterly NER/ISE Manager's meeting to increase communications between the sites, followup on specific issues, and discuss suggestions to improve NER and ISE efficiency. ISE participation in these meetings has been recently initiated. A proposed TS change is in progress to reorganize NER and ISE under a single corporate manager.

The inspector concluded that the overall performance of the ISE group was good. Self-initiated improvement for the site ISE staff and the proposed corporate reorganization exhibited ongoing efforts to improve the efficiency of the TS required review function. No issues were identified by the inspectors and compliance with the TS requirements was being accomplished.

c. On July 14, the inspectors monitored the licensee's PERP meeting which discussed Incident Investigation II-S-92-057. The event involved a containment ventilation isolation (CVI) which occurred on Unit 2, train A. The CVI initiated during channel functional testing of the A train noble gas containment purge exhaust radiation monitor (RM), 2-RM-90-130. The testing was performed per SI-82.2, FUNCTIONAL TESTS FOR RADIATION MONITORING SYSTEM, Revision 10. The CVI occurred at the same time the blocked RM exceeded its high radiation alarm limit during the test. During the investigation, the RM was verified electrically blocked from the CVI circuit and no malfunction of the block switch could be identified. The team also reviewed possible faults in the test configuration for the RM; however, no problems were identified. The investigation team did not identify a specific root cause for this event and concluded that an undetermined circuit failure initiated the CVI. The team recommended to management that additional testing be performed to further test the circuit, test points, and handswitch to identify possible fault paths. The team also identified that the performance of the SI was not precisely as written in the procedure. This performance problem was evaluated as not contributing to the cause of the subject CVI; however, a similar CVI event had occurred while performing SI-82.2 due to errors made by IM personnel when steps in the procedure were performed out of sequence. Licensee management reviewed this problem and indicated to the inspectors that the intent of the procedure was accomplished; however, revisions to the procedure were warranted to ensure procedure compliance will be maintained during future performance. The applicable procedures are being revised by personnel involved in the event. The inspectors concluded that the II team was thorough in their evaluation and conservatively recommended further investigation of the root cause of the CVI.

On July 31, the inspectors were informed that the additional testing recommended by the II team revealed further information related to the root cause of the event. Final disposition of the root cause will be reflected in a revision to the LER covering the event.

d. On July 28, the inspectors monitored the licensee's PERP meeting which discussed Incident Investigation II-S-92-060. The event involved RHR pump 2B-B inoperability due to a wiring probl with flow switch 2-FS-74-24. On July 17, 1992, at approximately 10:00 a.m. EDT, during an ASME Section XI IST pump test for the 2B-B RHR pump, a problem was identified with the miniflow valve operation in that it was cycling open and closed. The licensee entered TS LCO 3.5.2 and 3.6.2.1 for RHR at this time. At approximately 6:00 p.m., the licensee identified the cause to be a incorrectly landed field wire. The licensee corrected the deficiency and successfully completed the RHR IST, and exited TS LCOs 3.5.2 and 3.6.2.1 at 9:49 p.m. on July 17. The licensee initiated an Incident Investigation team on July 18, 1992, to review these events. Licensee investigation identified incorrect miniflow valve flow switch retermination had been performed following maintenance on July 1, 1992. The licensee determined that the effect of the wiring error would be to cause repetitive cycling of the miniflow valve when RCS pressure is greater than pump discharge pressure. Subsequent investigation concluded that the valve motor was not rated for this type of continuous duty and could be expected to fail after approximately 15 minutes. Failure of the miniflow valve in the closed position could result in dead-heading of the RHR pump, thus causing pump failure. Failure of the valve in the open direction coupled with failure of the other RHR pump could cause insufficient RHR system flow during the recirculation phase of accident mitigation.

Root causes identified by the licensee were determined to be personnel inattention to detail in that an inadequate self-check work practice was applied and the second party verification was not effectively implemented. Also, post-maintenance test requirements were not accomplished to ensure that the miniflow valve operated properly after this repair. Unit 2 was operating at approximately rated power during the time the 2B-B RHR pump was potentially inoperable.

The Incident Investigation team presented the above results to plant management on July 28, 1992. Upon hearing the results, the inspectors and licensee management concluded that the condition warranted additional investigations of potential reportability for being outside of the design basis of the plant. With the potential failure of the 2B-B RHR pump, and an assumed failure or other reason for inoperability of the opposite train ECCS system and/or components, the unit potentially could have operated outside of its design basis. During a postulated small break LOCA event, the 2B-B RHR pump would operate on recirculation until RCS pressure was less than RHR discharge pressure. Until that time when RHR would inject, the miniflow valve could have cycled, failed, and subsequently caused the 2B-B RHR pump to fail. With the assumed single failure criteria of the opposite 2A-A RHR pump or another A train ECCS component, no RHR and/or long term recirculation flow would be available once RCS pressure decreased below the RHR discharge pressure range. Investigation later determined that the 2A-A EDG, which supplies emergency power for the 2A-A RHR pump (opposite train) was out of service for routine maintenance on July 8, 1992, from 5:00 a.m. to 10:01 p.m. (approximately 17 hours). The licensee reported this condition to the NRC per 10 CFR 50.72.b.1.ii.B on July 28, 1992, as potentially outside of the design basis of the plant, in that both RHR pumps would have been inoperable. In addition, during the time period of July 1 to July 17, the licensee may not have been able to meet single failure criteria for RHR system operability. Other A train ECCS components were also later identified as being out-of-service during the timeframe that the 2B-B RHR pump may have failed. The licensee's analysis of the event is continuing.

The inspectors reviewed TS requirements relative to the event. TS LCO 3.5.2.d requires that two independent emergency core cooling system (ECCS) subsystems shall be operable with each subsystem comprised of one operable residual heat removal pump in Modes 1, 2, and 3. In addition, TS LCO 3.6.2.1.b.1 requires that two independent containment spray subsystems shall be operable with each subsystem comprised of an RHR spray train with one operable RHR pump. During the time period of July 8 from 5:00 a.m. to 10:01 p.m. EST, the 2B-B RHR pump was considered to be inoperable, and the 2A-A RHR pump did not have its emergency power source. Thus, the licensee potentially had no RHR pumps available and did not satisfy TS LCOs 3.5.2.d and 3.6.2.1.b.1. Other instances were also identified in which other A train ECCS components were taken out of services during the time period of the potentially inoperable 2B-B RHR pump. The licensee plans to address the safety significance of the events in an LER. The inspectors will review the licensee's conclusions during closeout of the LER.

The inspectors also reviewed the event with regard to licensee requirements identified in Site Standard Practice (SSP) 12.6, INDEPENDENT VERIFICATION, Revision 1, which specifies provisions for independent and second-party verifications associated with PMT activities. Section 3.3.4 states, in part, that a second party verification and a functional test may be specified instead of an independent verification in work orders and approved plant procedures. This is provided that the testing does, in fact, verify operability of each component under consideration. SSP-

12.6, Section 3.1.5 further states, in part, that the preparers of site procedures/instructions shall ensure that applicable site procedures/instructions provide for independent verification/second party verification as appropriate. The inspectors determined that on or before July 1, 1992, the licensee failed to specify and perform an adequate functional test in conjunction with second-party verification. Prior to the event, licensee personnel did not specify an adequate functional test, therefore, independent verification should have been prescribed in lieu of the post-maintenance testing requirements. Failure to follow the requirements of SSP-12.6 is identified as a violation (VIO 328/92-22-02). This violation resulted in one train of RHR being declared inoperable on July 17, 1992.

The inspectors also reviewed the event with regard to licensee adherence to requirements identified in Preventive Maintenance procedure PM 030272002. This PM detailed actions for verifying that correct configuration was attained after work activities were performed on flow switch 2-FS-74-24. On July 1, 1992, the licensee failed to adequately perform activities in accordance with preventive maintenance procedure PM 030272002. This action contributed to a mislaid wire termination and potentially affected operability of the 2B-B RHR pump. This is identified as a second example of VIO 328/92-22-02.

The two violation examples listed above were similar to events detailed in NRC Inspection Report 327, 328/91-31. This report reviewed an event involving a failure of the licensee to identify a electrical jumper left installed after maintenance activities on a Main Steam Isolation Valve. Second party verification failed to remove the installed jumper. A failure to specify independent verification or provide for an adequate functional test associated with the second party verification also occurred.

The inspectors also reviewed the licensee's reporting timeliness with regard to the event. Subsequent to the Section XI RHR pump test in which the miniflow valve cycled open and closed, the licensee entered appropriate TS LCOs for the inoperable RHR pump. However, several opportunities appear to have existed in which the licensee may have had reasonable information to identify the significance of the issue. Upon NE's completion of their review of the event, and prior to the II team's presentation of the events to licensee management at the PERP meeting, opportunity existed for review to determine the safety significance and whether a report was warranted consistent with 10 CFR 50.72.b.1.ii.B. A more timely investigation of the safety significance by the licensee would have identified that the plant was potentially outside of the design basis. Previously, NRC Inspection Report 327,328/92-17 identified another instance of reporting timliness, which may indicate the need for further management review of this area.

Within the areas inspected, two additional examples of a violation for failure to follow procedures were identified.

7. Licensee Event Report Review (92700)

The inspectors reviewed the LERs listed below to ascertain whether NRC reporting requirements were being met and to evaluate initial adequacy of the corrective actions. The inspector's review also included followup on implementation of corrective action and/or review of licensee documentation that all required corrective action(s) were either complete or identified in the licensee's program for tracking of outstanding actions.

a. (Closed) LER 327/92-01, Failure to Perform a Surveillance Requirement Because of Procedural Inadequacies. The issue involved a failure to calibrate a load sequence timer associated with the B train electric board room air handling unit within the required TS frequency. TS 4.8.1.1.2.d.10 requires that these timers be verified operable at least once per 18 months during shutdown. The root cause of this event was a weakness in the site standard governing work requests (WRs). No requirements existed for the initiator of a WR written to satisfy a TS surveillance to ensure that these WRs are registered in the surveillance program. After discovery of the missed surveillance, the timers were calibrated and found to be within tolerance. The inspectors discussed the root cause and corrective actions with licensee personnel, and verified that procedures were revised. Specifically, procedure SSP-6.21, Initiator of Work Requests, Rev. 2, was revised such that WRs generated to satisfy TS surveillance requirements shall be coordinated with the Periodic Test Section. The licensee also performed Incident Investigation No. II-S-92-003 as a result of this event. The inspectors verified that additional corrective actions and commitments noted in the LER were completed.

The above LER referenced a similar event, which occurred as described in LER 327/91-01. This LER involved failure to calibrate these same sequence timers due to an omission of these components from the SI program. As part of their corrective action, the licensee added these timers to the SI program. In addition, II-S-91-003 was written to investigate LER 327/91-01, and provided recommendations to prevent recurrence.

The inspectors concluded that the corrective actions in response to LER 327/91-01 were not sufficient to prevent recurrence. Corrective action was not adequate to ensure that once the timers were added to the SI Program, the surveillance would be performed at the required TS frequency. Thus, the licensee failed to meet the requirements of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action. Failure to prevent recurrence of a missed TS surveillance is identified as violation (327/92-22-03). This violation will not be cited because the licensee's efforts in investigating, identifying, and correcting the violation meet the criteria specified in Section VII.B of the Enforcement Policy.

b. (Closed) LER 327/92-06, Failure to Properly Verify Reactor Coolant System Flow Above Technical Specification Limits. The issue involved licensee identification of a condition where indicated RCS flow in the control room was below the minimum required by TS. This event was discussed and short term corrective actions were reviewed in inspection report 327, 328/92-03. A violation was identified in that report for failure to follow the procedural requirements of the surveillance instruction. Additional reviews of licensee's longer term corrective actions will be accomplished by the inspectors during closeout of the violation.

c. (Closed) LER 327/92-08, Inadvertent Containment Ventilation Isolation During Radiation Monitoring Testing. The event involved a Unit 1 CVI actuation due to personnel error while conducting post maintenance testing on a Unit 2 RM. Immediate corrective actions by operations was to verify that an actual CVI was not required and then to reset the signal and realign actuated equipment. An incident investigation was conducted and corrective actions were identified to prevent recurrence of the event including stressing the importance of self checking when working on instrumentation for one unit in close proximity to the same instrumentation for other unit. The inspectors reviewed the LER and the licensee's incident investigation report.

d. (Closed) LER 327/92-09, Potential Loss of Auxiliary Feedwater Condition Resulting From Inadequate Design Interfaces for the Anticipated Transient Without Scram Mitigating System-Actuation (AMSAC). The event involved licensee identification of a condition where when operating above 40% power, the motor driven AFW pumps circuit breakers would lock out under certain design conditions when required to mitigate an ATWS event. Both units were shut down at the time of discovery of the condition. Licensee corrective actions were to implement design changes to the circuitry prior to either unit operation above 40% power. Also, the licensee reviewed the design change process currently in place and concluded that interface reviews at various stages of the design process would prevent this type of error from being made today. The inspectors monitored licensee's corrective actions.

e. (Closed) LER 327/92-10, Turbine Trip Followed by Reactor Trip as a Result of Loss of Load. The event involved a reactor trip from approximately 100% power on Unit 1 when a ground occurred within a gas-operated relay on the Phase B main transformer. Operator and plant responses to the reactor trip were in accordance with procedures and as designed. A post trip investigation was conducted and all necessary actions for restart of the unit were identified and corrected. The inspectors monitored licensee actions associated with the reactor trip and restart investigation.

f. (Closed) LER 327/92-11, Safety Injection and Reactor Trip Initiated by a Low Steam Line Pressure Signal Resulting From Inadvertent Opening of Steam Dump Valves. The event involved a failure of the steam dump control circuitry during Mode 3, and resulted in the inadvertent opening of the steam dump valves. The licensee performed troubleshooting on the control circuitry, and no component failures were identified. The cause of the malfunction of the control circuitry could not be determined. The licensee replaced the components that coul have caused the steam dump valves. The inspectors concluded the licensee's troubleshooting to determine a definitive root cause to be adequate.

g. (Closed) LER 327/92-12, Manual Reactor Trip as a Result of Secondary System Perturbation. The event involved a failure of both No. 7 heater drain tank pumps (HDTPs) due to the failure of the No. 7 heater drain tank (HDT) level control valve positioner. A failure of the positioner caused 1-LCV-6-190A to fail full open, resulting in a rapid loss of level in the No. 7 HDT. The rapid loss of level caused the level indicating controller to drive the bypass level control valve, 1-LCV-6-190B, further closed and caused the No. 7 HDTPs to trip. This resulted in a rapid increase of water level in the HDT and isolation of the heater string since, as a result of the magnitude and rate of the level changes, 1-LCV-6-190B could not respond quickly enough to overcome the transient. Operations began decreasing load, and were instructed to manually trip the reactor if isolation of the low pressure heaters occurred. When the heaters isolated, the unit was manually tripped. The control room staff responded as prescribed and took actions necessary to stabilize the unit in a safe condition. The inspectors consider the licensee's investigation into the cause of the trip to be satisfactory.

h. (Closed) LER 328/92-03, Inoperable Mechanical Snubber. The event involved the licensee's identification of a snubber which was not properly connected to its supports. Discovery w made during the Unit 2 Cycle 5 refueling outage and review of work concluded that the snubber was not properly reconnected during the Unit 2 Cycle 4 refueling outage. An engineering evaluation was performed of this condition and it was concluded that system operability had not been effected. The licensee reconnected the snubber to the supports in accordance with approved work documents. Also, a field walkdown of the snubbers associated with similar configurations did not identify any other deficiencies. The licensee submitted Revision 1 to the LER which provided additional details as to the cause of the inoperable snubber. They determined that a temporary employee failed to follow procedural requirements with regard to documenting work configuration during performance of a work request in the Cycle 4 outage. Prior to discovery of the event, the licensee had strengthened work processes and controls for temporary personnel. The inspectors verified that additional management attention has been focused on work verification processes and controls.

i. (Closed) LER 328/92-04, A Containment Ventilation Isolation Occurred as a Result of a Spurious Opening of a Breaker in the Power Supply Circuit for Radiation Monitors. The event involved a spurious CVI actuation due to opening of the Train A power supply breaker to the lower containment radiation monitors. Immediate corrective actions were for operators to verify that no high radiation condition actually existed, and then to reset the CVI signal and return the radiation monitors to service after electrical troubleshooting determined that no electrical problem existed. Although no problem was identified with the breaker that was found open, the licensee replaced the same as a conservative measure.

j. (Closed) LER 328/92-05, Inoperability of a Main Steam Check Valve as a Result of Interference Between the Counter-Weight Arm and the Packing Stud. The event involved the licensee's identification of interference between a packing gland stud and a main steam check valve arm which could have effected valve operation. This event was addressed in NRC Inspection Report 327, 328/92-15. In that report a violation was identified for failure to properly conduct maintenance activities resulting in inoperability of the valve. Licensee corrective actions for the event were reviewed and considered to be adequate.

k. (Closed) LER 328/92-06, Failure to Perform a Surveillance Instruction Within the Required Timeframe. The event involved operations failure to assure that sampling of the Unit 2, No. 4 cold leg accumulator was accomplished after a level change of greater than or equal to 1% tank volume as required by TS. After discovery of the missed surveillance, immediate sampling was conducted and it was determined that the tank boron concentration was well within TS limits. Additional review of this problem concluded that a lack of formal communications and inadequate identification of the need for sampling during shift turnover also contributed to the failure to sample the tank when required. The inspectors reviewed the event, including ongoing actions associated with implementation of an operations improvement plan and consider that this item was being addressed in that plan; however, insufficient time had passed at the time of implementation of corrective actions for the improvement plan to realize full effects. The inspectors will continue with their review of operator performance as part of closeout for violations associated with the operations department conduct of operations.

l. (Closed) LER 328/92-07, Entry Into Mode 4 Operation Without Two Operable Containment Spray Systems Caused by Inadequate Configuration Control. The event involved operation of Unit 2 in a MODE prohibited by TS. This event was discussed in inspection report 327, 328/92-17. In that report, a violation was identified for failure to follow the requirements of TS 3.0.4 and TS 3.6.2.1. The licensee has instituted extensive corrective actions for this event which will be evaluated for effectiveness as a part of closeout of the violation.

Within the areas inspected, one non-cited violation was identified.

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

a. (Closed) URI 327, 328/90-22-04, Unissued Calculation for 1E Cable Testing. The issue involved use of an engineering calculation without proper issuance. This issue was investigated by the NRC Office of Investigations and a synopsis report of their findings (Report No. 2-90-019) was sent to TVA by letter dated April 10, 1992. As a result of the NRC investigation, NRC violations were identified. These violations were sent to TVA in a letter dated July 2, 1992. The first violation involved a failure to initiate prompt corrective actions and the second violation involved the failure to provide complete and accurate information regarding a material matter in TVA's submittal to the NRC dated March 28, 1990. These two items are identified as a violation (327, 328/92-22-04) in this report for purposes of followup on corrective actions.

b. (Closed) VIO 327, 328/90-28-01, Failure to Identify and Correct a Significant Condition Adverse to Quality. This issue involved the licensee's failure to identify and correct a problem pertaining to gas accumulation in CCP suction piping. The licensee failed to use vendor recommendations and other generic industry information to take action to prevent gas binding of the CCPs. As a result, a CCP actually became inoperable due to gas binding on August 22, 1990. This issue was also previously discussed in NRC Inspection Reports 327, 328/90-28, 90-32, and 91-23. The licensee's corrective action for the violation included reviews of previously evaluated NRC Information Notices, vendor recommendations, and industry corrective actions for identified problems, in order to assure proper licensee evaluations were performed. During the Unit 1 and Unit 2 cycle 5 refueling outages, the licensee performed modifications to test a possible passive vent system in order to alleviate the accumulation of gas in the CCP suction lines. The results of the testing indicated that the system could not adequately limit the gas accumulation below acceptable levels. The licensee plans to continue local venting of the CCP suction lines as an interim resolution to alleviate gas accumulation until remote (control room) venting to the hold-up tank can be accomplished via modifications scheduled during the cycle 6 refueling outages. The inspector periodically verified that the venting of the CCP suction lines was being accomplish r r the appropriate procedural controls. The licensee plans t revise LER 328/90-12 to reflect the permanent resolution of the issue by

August 24, 1992. The actions taken for the violation appeared adequate to address the root cause of the event.

c. (Closed) 327, 328/P2191-03, Part 21 Report from The Rockbestos Company - Revision of KS 500 Silicone Rubber Activation Energy Values. The issue involved identification of a potential hazard with the subject cable material; specifically that under certain operating conditions, qualified life of the affected cables could be shorter than previously calculated. The vendor letter indicated that they notified TVA of this condition and identified several purchase orders under which TVA was supplied the subject cable. The licensee was unable to determine that they had received notification of the subject Part 21 issue and wrote problem evaluation reports (CHPER920011 and SQPER920231) to address this issue. The inspectors reviewed the licensee's actions with regard to the Part 21 cable issue and the initial evaluation of Sequoyah PER (SQPER920231). That evaluation concluded that Rockbestos KS-500 cable in use at Sequoyah had a remaining qualified life of at least 1.9 years as of July 19, 1992.

On July 7, the inspectors were provided with the evaluation and corrective actions for CHPER920011. That report identified a condition where correspondence for the Part 21 issue from Rockbestos may not have been received by TVA. The vendor was not able to provide documentation that TVA received the subject notice due to a loss of records. Also, TVA moved the individual who the vendor stated that they had mailed the report to from Knoxville to Chattanooga prior to the report being mailed. This change may have contributed to the chance that the correspondence may have been lost if it was received. TVA implemented extensive short term corrective actions based on the PER conclusions. They included immediate reviews of the Part 21 condition at operating sites to assure the issue was properly dispositioned. Also, a reminder was placed in the NER weekly news to advise personnel of their responsibility regarding processing of 10 CFR Part 21 information received from vendors; and, the licensee implemented provisions to obtain and forward all Part 21 reports received into the NRC public document room to the nuclear experience review group for preliminary evaluation. Longer term corrective actions included provision for formalizing some of the short term actions in Nuclear Power Standards, and other correspondence between Vice Presidents to remind personnel of their duties regarding the forwarding of Part 21 information received from vendors. The inspectors reviewed the licensee's corrective actions and concluded that, even though there was a reasonable conclusion made that the correspondence may not have been received, the corrective actions were appropriate.

d. (Closed) 327, 328/P2191-05, Part 21 Report from Limitorque - Potential Failure of SMB 00 Torque Switch Roll Pins Depending on Licensee Operating Conditions. The defective component is the torque roll pin used in the SMB, SB, and SBD 00 actuators (serial numbers 233218 and greater) with heavy spring packs. Vendor studies of pin failures have revealed that the SMB 00 nuclear torque switch may fail when declutched under maximum rated load. Testing has exhibited that failure of the subject pins may occur after eleven declutching operations from the torque seated condition. The licensee was requested by the vendor to perform a complete review of standard operating conditions of installed SMB 00 actuators with heavy spring packs to determine the frequency of the torque seat declutching operation and the potential for operator failure. The inspectors reviewed the licensee's activities, including schedule for replacement of torque switches, and MOV failure history attributed to the subject Part 21. The licensee indicated that no MOV failures have occurred which were a result of torque switch roll pins. The licensee has replaced all affected torque switches on Unit 1. Of the 56 torque switches on Unit 2 MOVs, 26 have been replaced. The licensee has scheduled replacement of the remaining 30 during the upcoming Unit 2 cycle 6 refueling outage. The inspectors consider the licensee's completed activities, and those planned for the upcoming outage, to be sufficient to close item 327, 328/P2191-05.

e. (Closed) 327, 328/P2191-09, Part 21 Report from Morrison-Knudsen - Dimensional Problems may Exist in Certain Cutler-Hammer Contactors Used in Immersion Heating System. The licensee was informed of the issue after failure of several Cutler-Hammer contactors. A failure report from Cutler-Hammer indicated that dimensional problem existed in the contactor mold which caused an internal bind in the overload reset mechanism and intermittent circuitry on the overload contact. The vendor indicated that the manufacturing problem existed between January 1, 1987 and May 15, 1989. The following specific contactors were affected:

EMD P/N 8455508 (Cutler-Hammer P/N A10DNYZ)
Cutler-Hammer A10 Series (NEMA Size 1,2, and 3)

Prior to the vendor identification of the issue per 10 CFR Part 21, the licensee had initiated CAQR SQP890520, dated September 25, 1989, due to numerous failures associated with the EDG immersion heaters and contactors. Problems with the heaters were identified as an installation problem and were subsequently corrected by the licensee. The contactor problem, which was the subject of the Part 21, was evaluated by the licensee per NER report number 900682. The licensee inspected and identified suspect contactors at the EDGs, storage facilities, and other locations as applicable. Four defective overload relays were identified on the EDGs during a system engineer walkdown. Nine additional relays were identified in the licensee's storage facilities. The licensee removed the affected equipment, as identified by the Part 21 component date codes. Subsequently, the licensee issued DCN M08138A to remove the overloads on the subject contactors due to the overload function not being needed in the EDG immersion heater application. As of March 27, 1992, all modifications to bypass the overload relay circuit on the diesels have been accomplished. The inspectors concluded that the subject Part 21 Report was properly dispositioned within the licensee's NER program. In addition, the licensee was proactive in identification of the problem with the contactor and interacting with the vendor prior to the issuance of the Part 21 Report.

f. (Closed) URI 327, 328/91-03-01, Incident Investigation Review of Removal of Snubber from RHR Line. The issue involved review of licensee revision to II-90-119 which addressed several items including event sequence and root causes for the event. The inspectors reviewed licensee actions with regard to the issue and concluded that they were adequate.

g. (Closed) VIO 327, 328/91-04-01, Failure to Follow the Requirements of AI-30, TS 3.8.1.1, and 10 CFR 50.73. The violation involved a failure to respond adequately to an alarm annunciator related to proper operation of emergency diesel generators. The minimum air pressure required to TVA procedures for air start accumulator to meet its required capability is 180 psig. As a result of the failure of control room operators to properly acknowledge the alarm, air pressure decreased to 140 psig. Eventually, the low pressure on the air start accumulator was discovered and promptly reported to the control room by an Auxiliary Unit Operator who heard the low pressure alarm while in the diesel building. This violation resulted in a $75,000 Civil Penalty.

The inspectors reviewed the licensee's response to the violation, including corrective steps taken to avoid recurrence. Among these activities include increased management emphasis in operator response to control room annunciator alarms, an upgrade of operating standards, establishment of an Operations review team, and independent review by senior management. Inspector observations of control room operators indicate an improvement in response to alarms. The licensee has made substantial progress in the control room "black-board" concept due in part to the upgrade of the overall annunciator system. The licensee has also been successful in the elimination of most control room nuisance alarms, which was a contributing factor in the violation. The inspectors consider the licensee's activities to be sufficient to close this violation.

h. (Closed) URI 328/92-15-02, Implementation of Operational Procedures to Support Bulletin 88-08 Response. The subject URI was identified due to the inspector's concerns that routine system operational practices may have pressurized the Boron Injection Tank (BIT or CCPIT) by removing double valve isolation contrary to the licensee's response to NRC Bulletin 88-08. In a response dated October 3, 1989, the licensee determined that the four 1.5 inch (3.81 cm) high head injection lines would not be subjected to thermal stresses subsequent to the boron injection tank removal.

This conclusion was based on double isolation being maintained for the injection lines by the four normally closed BIT isolation valves (two inlet and two outlet). If the BIT pressure should increase above normal operating pressure of the RCS (2235 psig or 15.4 MPa), a thermal stress condition in the injection lines could exist if the outlet valves to the BIT leak. On May 24, 1992, the licensee began experiencing inleakage through the Unit 2 BIT inlet valves, which resulted in pressurization of the BIT to approximately 2,400 psig (16.5 MPa), which is near the CCP discharge pressure. This abnormal condition caused the licensee to operate outside of the conditions stated in their response to the NRC Bulletin by removing the relied on double isolation.

During review of the inleakage problem, the inspectors noted that venting of the BIT was being accomplished via an existing CCP venting procedure in order to maintain the pressure in the BIT below 2,000 psig (13.8 MPa). However, during performance of the venting procedure, 2-SI-SFV-062-001.A, CENTRIFUGAL CHARGING PUMP 2A-A CASING AND DISCHARGE PIPING VENTING, Revision 0, the BIT pressure was equalized with the CCP discharge pressure, which exceeded the 2,000 psig value which the venting process was trying to maintain. On May 27, 1992, the licensee revised 2-SO-63-5, EMERGENCY CORE COOLING SYSTEM, to allow venting of the BIT without prior pressurization of the BIT. The inspectors also discussed concerns related to the routine use of 2-SI-SFV-062-001.A to vent applicable RCS piping to satisfy TS 4.5.2.b. This TS requires ECCS discharge pipe high point venting once every 31 days. The removal of double valve isolation due to performance of the venting procedure in response to the inleakage and during routine TS required venting evolutions appeared to have resulted in the licensee operating outside of their response to NRC Bulletin 88-08. During subsequent discussions with the licensee, the inspectors were informed that short term removal of the double isolation was considered by the licensee in their response to the Bulletin. However, explanations of this evaluation were not included in the response due to the licensee's conclusion that effect of short term cycling was not related to the failure mechanism described in the Bulletin. After further evaluation of the BIT leakage problems and their effect on the injection lines, the licensee has determined that operation with maintaining the BIT pressurized for the remainder of the current operating cycle on Unit 2 is acceptable. Discussions with the inspectors and NRC headquarters personnel were held to evaluate the above conclusions and system operation. No other problems were identified with the licensee's actions at this time. Other problems were noted with regard to the annunciator setpoint for the BIT. The inspectors questioned why the setpoint was at 2,400 psig when the operating pressure was to be maintained below 2,000 psig. Due to the above concerns, the licensee initiated PER SQ920201 on May 27, 1992 to document the problems and proposed corrective actions.

The inspectors also reviewed documentation associated with modifications the licensee instituted to maintain compliance with NRC Bulletin 88-08. In May of 1991, DCNs M5557A and M5558A addressed concerns of a potential leakage path around the BIT outlet isolation valves through normally open manual bypass valves 1-63-579 & 2-63-580. The DCNs were to allow closure and locking of the bypass valves in order to ensure double isolation for the injection lines was maintained in accordance with the Bulletin response. In the safety assessments for the DCNs, guidelines to maintain the pressure in the BIT below 2,000 psig were stipulated. The safety assessments addressed the before mentioned procedures for monthly venting and also quarterly Section XI tests which would not maintain the double isolation criteria of the Bulletin response. However, the inspectors raised concerns due to the identification that actions required by the safety assessment to establish a low pressure vent path down stream of the BIT outlet valves during the venting procedures were not yet performed. The licensee reviewed the implementation of the requirements of the safety assessment (SA). The inspectors were informed that although the SA required procedure changes, it did not specify an exact time period. An engineering judgement assumed that due to the short term cycling not providing an area of concern for the Bulletin, the procedure changes could and were scheduled to be made during upcoming procedure revisions. The inspectors concluded that the licensee's response to the Bulletin was adequate with regard to the subject URI; however, also concluded that more information should have addressed the issue in both the SA and the bulletin response.

Within the areas inspected, no violations were identified.

9. TI 2500/020 INSPECTION TO DETERMINE COMPLIANCE WITH ATWS RULE, 10 CFR 50.62

10 CFR 50.62 required that licensee's of nuclear power plants implement the requirements of the ATWS rule and obtain NRR acceptance their proposed plan for implementation of the rule. Sequoyah responded to the NRC of their proposal for implementation of the requirements of 10 CFR 50.62 in letters dated February 17, 1987; August 23 and October 25, 1988. The NRC, NRR issued a SER accepting the licensee's proposal to the rule in a letter dated September 14, 1989. Implementation of the equipment to comply with the rule was accomplished for Unit 1 and Unit 2 during the Cycle 4 refueling outages which were completed in 1990.

During this inspection period, the inspectors reviewed the implementation of the ATWS rule requirements, 10 CFR.50.62, and the effectiveness of the licensee's QA controls applied to ATWS activities. The inspection included a review of completed work activities. The inspectors reviewed selected work plans for installation of ATWS equipment and conducted a walkdown of installed equipment with the system engineer. No discrepancies were noted.

Within the areas inspected, no violations were identified.

10. TI 2515/112 LICENSEE EVALUATIONS OF CHANGES TO THE ENVIRONS AROUND LICENSED REACTOR FACILITIES

During this report period, the inspectors reviewed the licensee's program for periodic review, identification, and evaluation of changes in site proximity hazards and demography to determine their effect on the safety of the plant. The inspection was performed to verify that the licensee properly evaluated safety issues which had arisen from changes made near the reactor site involving population distribution or the introduction of new industrial, military, or transportation hazards. The inspectors reviewed the Sequoyah SER, and FSAR section 2.1, Geography and Demography, and section 2.2, Nearby Industrial, Transportation, and Military Facilities, and held discussions with the licensee.

The inspectors determined that the licensee does not have a completely formal program to periodically review all of the items identified in the TI. The licensee did inform the inspectors that SSP 4.2, MANAGEMENT OF THE FINAL SAFETY ANALYSIS REPORT (FSAR), Revision 0, Appendix B, identifies most of the attributes discussed in the TI for review during FSAR updates. The licensee does formally monitor population changes, changes in river traffic, and geological, seismological, hydrological, and meteorological features around the site. In response to the TI, the licensee is also considering performing an audit to look at some attributes of the TI. Based on discussions with the licensee and the inspector's knowledge of the plant and surroundings, little has changed from the information currently contained in the FSAR. In response to the inspectors questions, the licensee is evaluating the need for a formal program to monitor and evaluate changes in site environs.

Within the areas inspected, no violations were identified.

11. Exit Interview

The inspection scope and results were summarized on August 3, 1992 with those individuals identified by an asterisk in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. Although proprietary material was reviewed during the inspection, proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
328/92-22-01	Violation for failure to follow housekeeping and/or cleanliness requirements during maintenance activities around safety-related components. (paragraph 4.b)
328/92-22-02	Violation for failure to follow the requirements of SSP-12.6 and preventive maintenance procedure PM 030272002. (paragraph 6.d)
327/92-22-03	NCV for failure to prevent recurrence of a missed TS surveillance. (paragraph 7.a)
327, 328/92-22-04	Violation for failure to initiate prompt corrective actions and failure to provide complete and accurate information regarding a material matter in your submittal to the NRC dated March 28, 1990. (parapraph 8.a)

Strengths and weaknesses summarized in the results paragraph were discussed in detail.

Licensee management was informed of the items closed in paragraphs 7, 8, 9, and 10.

12. List of Acronyms and Initialisms

AFW - Auxiliary Feedwater
AI - Administrative Instruction
AIT - Augmented Inspection Team
ALARA - As Low As Reasonable Achievable
AMSAC - ATWS (Anticipated Transient Without Scram) Mitigation System Actuation Circuitry
ASOS - Assistant Shift Operations Supervisor
AUO - Auxiliary Unit Operator
CAQR - Condition Adverse to Quality Report
CCP - Centrifugal Charging Pump
CECC - Central Emergency Control Center
CFR - Code of Federal Regulations
CILRT - Containment Integrated Leakage Rate Test
COMS - Cold Overpressure Mitigation System
COPS - Cold Overpressure Protection System (Same as COMS)
CR - Control Room
CREVS - Control Room Emergency Ventilation System
CVI - Containment Ventilation Isolation

DCN	-	Design Change Notice
DRP	-	Division of Reactor Projects
EDG	-	Emergency Diesel Generator
EHC	-	Electro-hydraulic Control
ERCW	-	Essential Raw Cooling Water
ESF	-	Engineered Safety Feature
FME	-	Foreign Material Exclusion
FSAR	-	Final Safety Analysis Report
GPM	-	Gallons per Minute
IFI	-	Inspection Follow-up Item
ISI	-	Inservice Inspection
IST	-	Inservice Testing
KV	-	Kilovolt
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
LPDR	-	Local Public Document Room
LPM	-	Liters per Minute
LOCA	-	Loss of Coolant Accident
MDAFW	-	Motor Driven Auxiliary Feed Water
MSIV	-	Main Steam Isolation Valve
M&TE	-	Measurement and Test Equipment
NRC	-	Nuclear Regulatory Commission
NRR	-	Nuclear Reactor Regulation
ODCM	-	Offsite Dose Calculation Manual
PCR	-	Personnel Contamination Report
PER	-	Problem Evaluation Report
PERP	-	Plant Evaluation Review Panel
PI	-	Periodic Instruction
PMT	-	Post-maintenance Test
PORC	-	Plant Operations Review Committee
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RPI	-	Rod Position Indication
RPM	-	Revolutions Per Minute
RTD	-	Resistance Temperature Detector
RWP	-	Radiation Work Permit
SFP	-	Spent Fuel Pit
SG	-	Steam Generator
SI	-	Surveillance Instruction
SOS	-	Shift Operating Supervisor
SRO	-	Senior Reactor Operator
SSP	-	Site Standard Practice
SSPS	-	Solid State Protection System
TI	-	Test Instruction
TROI	-	Tracking and Reporting of Open Items
TS	-	Technical Specifications
TVA	-	Tennessee Valley Authority
URI	-	Unresolved Item
USAR	-	Updated Safety Analysis Report
VCT	-	Volume Control Tank
WP	-	Work Plan
WR	-	Work Request