UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-327/94-41 and 50-328/94-41

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: November 6 through December 3, 1994

Lead Inspector: _____ FOR _____ 12/27/94
W. E. Holland, Senior Resident Inspector Date Signed

Inspectors: S. M. Shaeffer, Resident Inspector
R. D. Starkey, Resident Inspector
S. E. Sparks, Project Engineer
D. A. Seymour, Resident Inspector
B. R. Crowley, Reactor Inspector
N. Economos, Reactor Inspector

Approved by: _____ 12/27/94
Mark S. Lesser, Acting Chief, Branch Date Signed
Division of Reactor Projects

SUMMARY

Scope:

Routine resident inspection was conducted in the areas of plant operations, maintenance observations, surveillance observations, onsite engineering, plant support, effectiveness of licensee controls in identifying, resolving, and preventing problems, and Licensee Event Report closeout. During the performance of this inspection, the resident inspectors conducted several reviews of the licensee's backshift and weekend activities at the plant.

Enclosure 2

Results:

In the area of Operations, a violation was identified for failure to follow the Conduct of Operations procedure and failure to provide an adequate fuel handling procedure during/for conduct of fuel movement evolutions in the spent fuel pool area. Furthermore, lighting conditions for operations were inadequate, which contributed to an incident where the spent fuel pool bridge hoist cable separated from the hoist drum. This indicated a weakness in the level of safety sensitivity for fuel pool operations (paragraph 3.c).

In the area of Engineering, engineering involvement was noted to be good in troubleshooting problems related to Unit 2 turbine driven auxiliary feedwater pump bearing/control oil fluctuations (paragraph 4.a).

In the area of Engineering, licensee corrective actions for a condensate system pipe break event were adequate to reasonably assure system integrity. The event also provided additional information regarding the failure mechanism which should be factored into the erosion/corrosion monitoring program. However, additional management attention should be focused on areas including communications between E/C personnel and other departments, BOP equipment configuration drawings, and thoroughness of erosion/corrosion reviews (paragraph 6.b).

REPORT DETAILS

1. **PERSONS CONTACTED**

Licensee Employees

*O. Zeringue, Senior Vice President, Nuclear Operations
*R. Adney, Site Vice President
*J. Baumstark, Plant Manager
D. Brock, Maintenance Manager
L. Bryant, Outage Manager
*M. Burzynski, Engineering & Materials Manager
D. Clift, Acting Planning and Technical Manager
*M. Cooper, Technical Support Manager
R. Driscoll, Nuclear Assurance & Licensing Manager
F. Fink, Business and Work Performance Manager
*T. Flippo, Site Support Manager
J. Gates, Outage Manager
G. Enterline, Operations Manager
*O. Hayes, Operations Program Manager
*C. Kent, Radcon/Chemistry Manager
*B. Lagergren, Manager of Projects
D. Lundy, Engineering & Materials Program Manager
*K. Meade, Acting Compliance Manager
J. Patrick, Maintenance Program Manager
L. Pogue, Site Quality Assurance Manager
R. Rausch, Maintenance and Modifications Manager
G. Rich, Chemistry Manager
J. Robertson, Independent Analysis Manager
*J. Symonds, Modifications Manager
*R. Shell, Site Licensing Manager
M. Skarzinski, Manager, Methods and Procedures Group
J. Smith, Regulatory Licensing Manager
N. Welch, Operations Superintendent
K. Whittenburg, Public Relations Manager

NRC Employees

M. Lesser, Acting Chief, Branch 4, DRP
*W. Holland, Senior Resident Inspector
*S. Shaeffer, Resident Inspector
*R. Starkey, Resident Inspector
*D. Seymour, Resident Inspector
*S. Sparks, Project Engineer
B. Crowley, Reactor Inspector
N. Economos, Reactor Inspector

* Attended exit interview.

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

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

On November 8, 1994, TVA Nuclear announced that Mr. Robert Adney had been appointed to be the Site Vice President for the Sequoyah Nuclear Plant effective November 28, 1994. Mr. Adney will fill the senior management position at Sequoyah which had been temporarily filled by Mr. Ike Zeringue, Senior Vice President, Nuclear Operations.

On November 18, 1994, Mr. J. P. Stohr, Director, Division of Radiation Safety and Safeguards, Region II, visited the Sequoyah Nuclear Plant. Mr. Stohr toured the plant with the resident inspectors and met with several managers at the plant.

On November 30, 1994, Mr. S. D. Ebneter, Region II Administrator, visited the Sequoyah Nuclear Plant. Mr. Ebneter met with the resident inspectors, attended the plant morning meeting, met with senior plant management, and toured the plant with the resident inspectors.

2. PLANT STATUS

Unit 1 began the inspection period operating at power. The unit operated at approximately full power until November 21, when power was reduced to approximately 87 percent to make repairs to the 1B condensate booster pump because of vibration higher than normal. After repairs were completed, the unit returned to full power operation on November 26. The unit operated at power until November 29, when it experienced a reactor trip from approximately 100 percent power. The event is further discussed in paragraph 3.d. Approximately 3 hours after the reactor trip, a leak was identified in a condensate line between the #3 and #4 feedwater heaters in the BOP. This event is further discussed in paragraph 6.b. At the end of the inspection period, Unit 1 was making preparations to enter MODE 2.

Unit 2 began the inspection period in MODE 3 (day 125 of the Unit 2 Cycle 6 outage). Testing of the turbine driven auxiliary feedwater pump had identified problems resulting in the licensee receiving discretionary enforcement to continue troubleshooting/testing of the pump in MODE 3. This issue is further discussed in paragraph 4.a. After all testing was complete in MODE 3 and requirements were met, the unit entered MODE 2 (reactor critical) on November 11 and completed low power physics testing the next day. The unit entered MODE 1 on November 12, and connected to the grid on November 16, 1994. The unit increased power to approximately 30 percent over the next few days. On November 18, a steam leak of a test valve required that the turbine generator be taken off line to effect repairs. The turbine was taken off line late on November 18, repairs were accomplished, and the turbine was placed back on line. Unit 2 reconnected to the grid on November 19, and

continued power increase and appropriate testing over the next 7 days. Unit 2 reached full power operation on November 25, 1994, and operated at power for the remainder of the inspection period.

3. **PLANT OPERATIONS** (71707 and 92901)

a. Daily Inspections

The inspectors conducted selective examinations, on a day-to-day basis which involved control room tours, plant tours, and plan of the day/management meetings.

On November 29, 1994, at approximately 7:13 a.m., Unit 1 experienced an automatic reactor trip from approximately 100 percent reactor power. The reactor tripped due to an automatic turbine trip. The turbine trip was caused by a loss of both 48VDC EHC power supplies due to an electrical spike on the power supply output.

The inspectors responded to the control room after the reactor trip. They considered that operations crew performance to the reactor trip and stabilizing the unit in MODE 3 was good. They noted that operators were comparing information on sequence of events printouts with actual indication on annunciation first out windows. System engineering support was present and provided good assistance to operations personnel. After the trip, the cause of the loss of power to both EHC power supplies was not initially known.

After the trip, the post trip team was established to review the trip, determine cause, and recommend appropriate corrective actions. The inspectors reviewed the functions of the post trip review team and the PORC in paragraph 8.b.

b. Biweekly Inspections

The inspectors conducted inspections to verify operability of the emergency diesel generators (EDG). The inspectors reviewed configuration of EDG support systems such as air supply to the start motors, lube and fuel oil supplies and valve alignments, electrical alignments, and overall condition of the EDGs. Based on the reviews, the inspectors concluded that the EDGs support systems were in an operable condition.

However, the inspectors identified a concern regarding spare 6.9 KV cables coiled up in each EDG cubical above the excitation electrical cabinet. The spare cables were originally designed to tie into the fifth on-site EDG to allow it to be used as a swing EDG for any of the four TS required EDGs. The inspectors estimated each coil contained approximately 50 to 75 feet of cable

which were only restrained by small plastic ties and/or light rope. The inspectors questioned the seismic qualification of the mass of cables, their impact on surrounding equipment, and potential unknown loading of the supports on which they were resting.

The inspectors informed the licensee of their observation. PER SQ940990 was initiated by the licensee to resolve this issue. Reviews conducted by the licensee concluded that the estimated coil weight of less than 300 pounds would not adversely affect the structural qualifications of the supports. In addition, the licensee determined that the coils would not be dislodged from the structures and present a hazard to the switchgear. The licensee installed nylon rope restraints at those locations where only tie wraps were previously used. The inspectors concluded that the licensee adequately addressed the concerns related to these cables.

c. Monthly inspections

The inspectors conducted monthly inspections in the areas of clearance control, problem identification reports, and containment isolation lineups. Also, reviews of third party evaluations were conducted to determine if significant safety issues were identified.

During this period, the licensee commenced movement of spent fuel, in accordance with WO 94-01658, from the storage racks in the SFP to a temporary storage rack location in the cask storage area of the SFP. The purpose of this fuel movement activity was to facilitate the replacement of the existing fuel racks in the SFP with new high density fuel racks. An AUO was assigned to move the fuel using the SFP bridge crane hoist, and a worker, experienced with SFP activities, was assigned to be the spotter for the movement. A fuel handling supervisor (FHS), a licensed SRO, was assigned to supervise the activity, but was not required by operations management to be continuously present in the area.

As documented in PER SQ940963, approximately 11:00 a.m., on November 25, the AUO and spotter proceeded to recommence fuel movement by retrieving the spent fuel handling tool from its storage bracket on the SFP wall. Earlier in the shift approximately 10 fuel assemblies had been moved to the temporary storage rack location. As the handling tool was being moved from its storage bracket, the AUO and spotter felt a substantial jar to the hoist and bridge and immediately stopped movement of the hoist. At the time of the jar no fuel was attached to the fuel handling tool. The AUO did not observe any visible problem with the hoist nor did there appear to be any binding of the of the suspended load. He then lowered the tool approximately one foot when he noticed what appeared to be a loose cable end or loop in the cable on the hoist take-up drum. At that point, as a

precautionary measure, he tied off the tool to the bridge with a rope and then notified the FHS. When the FHS, who was not in the immediate area at that time, arrived on the fuel handling bridge, a decision was made to return the fuel handling tool to its storage bracket. While moving the tool back to the storage bracket, the hoist cable became slack and the weight of the tool was fully supported by the rope attached to the tool. The AUO and FHS then completed lowering the tool into its bracket using the attached rope.

After returning the tool to its storage location, the FHS directed that the refueling bridge be moved to the cask storage area of the SFP to permit examination of the hoist in a safe area, since there was no fuel stored in that part of the SFP. Prior to hoist movement, the hoist cable hook was also tied off to the bridge. As the hoist was being lowered to verify its operation, the cable became separated from the hoist drum and fell toward the cask storage pool. As it was falling, the FHS grabbed the cable and prevented it from falling into the pool. The loose cable was then tied off to the bridge and the SOS was notified.

Subsequent inspection of the spent fuel handling tool revealed a scraped/dented area near the bottom of the tool which indicated that it had caught on some object as it was being removed from its storage bracket. The area where the tool is stored allows for limited lateral movement and it is most probable that the tool momentarily caught on the lip of the nearby spent fuel storage rack which contained spent fuel assemblies. Cable tension then built up before the tool cleared the rack and the sudden release of tension apparently caused the cable to become detached from the hoist drum. The hoist cable was also determined to have been damaged from a overload condition. The licensee determined that poor lighting in the vicinity contributed to the improper positioning of the tool.

The inspectors reviewed the circumstances surrounding this event and discussed the event with the FHS and operations management. The inspectors had several concerns regarding this evolution. Specifically, procedure SSP-12.1, CONDUCT OF OPERATIONS, Revision 10, requires the FHS is to be present during any fuel (new or spent) movement, receiving, transfer, or shuffle. Although no fuel was attached to the handling tool when it was damaged, the intent of moving the fuel handling tool was to prepare for fuel movement and, in fact, fuel had been moved earlier in the shift when the FHS was not present in the immediate area. Discussions with operation's supervision and management indicated a lack of awareness of the procedural requirement that a FHS be present in the area during fuel shuffle. In fact, a Standing Order, SO-94-126, dated November 2, 1994, had been written describing the SFP rerack project and specifically stated that the SRO (FHS) was not required to be continually at the SFP site. The inspectors

considered the standing order to be an obvious contradiction to the requirements of SSP-12.1.

The inspectors also reviewed the fuel handling procedure FHI-3, MOVEMENT OF FUEL, Revision 26. The review determined that the procedure did not provide precautions or instructions regarding the retrieval and storage of the spent fuel handling tool in its storage bracket. The inspectors considered that inadequate instructions were provided in the fuel handling procedure which contributed to the event discussed above. Specifically the procedure lacked instructions to assure that while moving the handling tool in the vicinity of its storage area, it would not come in contact with the rack.

Technical Specification 6.8.1 addresses requirements for procedures to properly control and conduct evolutions relating to nuclear safety. Failure to follow procedure SSP-12.1 and the inadequacy of procedure FHI-3 during conduct of fuel movement evolutions is identified as a violation of TS 6.8.1 (VIO 327, 328/94-41-01).

The inspectors were also concerned that following the initial jar to the SFP hoist, the AUO and FHS operated the hoist without SOS approval or knowledge, or without requesting technical assistance. Apparently, prior to attaching a rope, the fuel handling tool was moved while being supported entirely by the hoist; a hoist which was later proven to be unsafe for use. During that tool movement the hoist cable could have become unattached from its take-up drum and the spent fuel handling tool would have then dropped on stored irradiated fuel. The inspectors considered that collectively, these problems, indicated a weakness in the level of safety sensitivity for fuel pool operations.

On December 1, 1994, the licensee resumed fuel shuffle activities. Prior to resumption, the SFP bridge and hoist were tested and the hoist cable was replaced. Additionally, new guidelines were implemented for removing/storing the fuel handling tool, and the FHS was required to be continuously present during fuel shuffle activities. The inspectors concluded that the licensee's immediate corrective actions were appropriate to allow resumption of fuel shuffle activities. However, management focus needs to be maintained to assure that evolutions relating to the spent fuel pool rerack modification are properly supervised and procedures are adequate.

d. Licensee NRC Notifications

On November 29, 1994 the licensee made a four hour notification to the NRC as required by 10 CFR 50.72 regarding an automatic reactor trip of Unit 1 from approximately full power. The reactor trip was initiated by a turbine trip. The turbine trip was caused by an electrical problem affecting the turbine EHC control system.

Approximately 3 hours after the reactor trip, the unit experienced a pipe crack on a 14 inch condensate line between the #3 and #4 feedwater heaters. Additional reviews of these events are discussed in paragraphs 3.a, 6.b, and 8.b. The licensee will submit an LER for the trip event.

Within the areas inspected, one violation was identified.

4. **MAINTENANCE OBSERVATIONS** (62703 and 92902)

During the reporting period, the inspectors verified by making observations, conducting reviews, and interviewing maintenance personnel, that the licensee's maintenance activities resulted in reliable operation of plant safety systems and components, and were performed in accordance with regulatory requirements. Inspection areas included the following:

a. UNIT 2 TDAFW PUMP BEARING/CONTROL OIL FLUCTUATIONS

During the inspection period, the inspectors reviewed activities associated with operability testing of the Unit 2 TDAFW pump. Initial testing of the pump is performed in MODE 4, including an uncoupled overspeed test run; however, final testing could only be accomplished with the unit in MODE 3, supplying conditions which can provide an adequate steam supply to support required testing per TS 4.7.1.2.a.2. Although TS 3.7.1.2 requires all three AFW pumps (two motor driven pumps and one steam driven pump) to be operable in MODES 3 and above, the TS allows the unit to be placed in MODE 3 with the TDAFW pump not fully tested, until steam conditions exist to support final testing (secondary steam supply pressure greater than 842 psig). Once secondary steam pressure is greater than 842 psig, TS 3.7.1.2, Action a, allows the TDAFW pump to be inoperable for up to 72 hours to complete the required testing prior to requiring a forced unit cooldown to MODE 4.

Initial Identification of Turbine Oil System Problems

The licensee entered the Action Statement of TS 3.7.1.2 and began MODE 3 testing of the TDAFW pump on November 4, 1994, at 6:52 p.m. Some minor delays in initial testing were attributed to adjustments to the TDAFW LCVs associated with modifications made to the valves during the outage and to pump instrumentation calibration problems. During final post-modification testing on November 6, the licensee identified a condition where turbine bearing/control oil was found on the pump skid after the pump was shut down. Additional pump operation identified that the oil was coming out of the turbine oil system at the top of the turbine outboard bearing housing, at the overspeed trip mechanism tappet. In addition, the inboard bearing sight glass level was decreasing below the minimum level indicator mark. Troubleshooting evolutions continued after discovery of the

problem on November 6 and 7; however, the problem appeared to be intermittent and no definitive root cause could be determined within the allowed TS LCO ACTION time frame.

Enforcement Discretion

As a result, on November 7, the licensee informed the NRC that the 72 hour allowed outage time provided by TS LCO 3.7.1.2, ACTION a, was insufficient to allow for additional testing opportunity to identify the problem. After consideration of all available testing options, the licensee then initiated discussions with the NRC to request Enforcement Discretion to remain in MODE 3 such that adequate steam to the pump would be available in order to continue troubleshooting the problem. Based on discussions held between the licensee, NRC Region II, and NRC Headquarters, enforcement discretion to allow for an additional 72 hours of testing/repair activities was verbally granted by the NRC on November 7, 1994. This was followed up by written permission in a letter dated November 9, 1994 (NOED 94-2-008).

The decision for allowing the additional time was based on the following. First, it was determined that, based on the decay heat load of the newly loaded core following the refueling outage, the safety consequences of the extension would be very low. Second, it was determined that if the unit was taken to MODE 4 per the requirement of TS LCO 3.7.1.2, ACTION a, appropriate testing to determine the root cause of the problem could not be accomplished. In addition, the licensee took additional measures to protect the other AFW pumps, minimizing any risk to the switchyard or the emergency power supplies to the Unit 2 motor-driven AFW pumps. Upon receiving the Enforcement Discretion, the licensee remained in MODE 3 and implemented their action plan to support the troubleshooting activities.

System Description

The TDAFW turbine oil system provides cooling/lubricating oil to the turbine bearings and other internal components, as well as acting as the control oil for the turbine EHC system. Total oil capacity of the system is approximately 7 gallons and level is indicated on a sight glass mounted on the inboard bearing housing. A sight glass is also installed on the discharge piping of the oil pump. The turbine oil system is skid mounted and consists of a shaft driven, gear-type pump, separate inboard and outboard bearing housings, each installed with a one inch drain leading to a reservoir, which also acts as an equalizing line between the two bearing housings. The reservoir consists of a round 3 inch diameter pipe, approximately 3.0 feet long. A slinger ring is also provided in each bearing housing to provide bearing lubrication during turbine startup and coastdown. A relief/bypass line is installed on the oil pump discharge piping, which allows for bypassing flow back to the oil pump's suction. This bypass line provides for system pressure and

flow control. The system was balanced to provide approximately 15 psig of oil pressure to the system, with distribution lines containing orifices feeding the various component functions. It should be noted that the outboard bearing housing also served as an oil return for the EHC and other oil functions in addition to the normal bearing flows; whereas, the inboard bearing housing only served to collect the inboard bearing expended oil capacities.

Unit 2 TDAFW Outage Modifications

During the Unit 2 refueling outage, several modifications were made to the TDAFW pump. These modifications included: changes to the TDAFW pump LCVs to allow them to fail open; scheduled replacement of the turbine governor controller and servo unit (the new EGR unit incorporated a slightly larger pilot valve, 0.312 inch diameter versus 0.250 inch); installation of a drain valve on the equalizer line; and leveling of the equalizing line per vendor recommendations, which also resulted in the equalizing line being raised approximately 1 inch.

Root Cause Determination and Corrective Action Modifications

Based on an iterative troubleshooting process which incorporated numerous pump runs, the licensee concluded that the problems could be associated with gas (air) entrainment in the turbine oil from normal agitation. This gas accumulated as voids in the outboard bearing housing drain line, resulting in reduction of normal flows and oil level fluctuations between the two bearing housings. The problem took between 20 and 40 minutes of pump operation to appear. Air voids were identified via ultrasonic testing at different locations in the outboard bearing housing drain line. The accumulation of air pockets, at some point, caused enough restriction of drain flow to cause the outboard housing oil level to exceed its capacity and overflow, simultaneous with the inboard housing losing level due to the oil pump predominantly taking suction from that housing. The inspectors considered that the turbine oil system would eventually fail due to the decreasing oil supply. The entrainment of the air in the oil was presumed to be taking place in both bearing housings, as the oil is sprayed onto the bearings and from other agitation caused by the discharge of turbine control oil (only in the outboard housing).

The licensee concluded that, based on the oil system design, air entrainment would occur, therefore, corrective actions should focus on mitigation of the effects of the entrained air. The primary corrective action for the problem was installation of an atmospheric vent at the top of the outboard bearing drain line. This allowed any entrained air to vent off, rather than restrict drain flow. In addition, a portion of the one inch outboard bearing housing drain line was replaced with 1.5 inch diameter piping.

The following additional troubleshooting and/or actions were also completed at some point during the activities: draining and replacement of the turbine oil; inspection of the bearing housing drain lines, oil distribution line orifices, and other components with a boriscope; replacement of system relief valve due to small amount of leakage; relief valve setpoint adjustment to allow reduction of pump discharge pressure from 15 psig to 10 psig; verification of integrity of piping connections; and verification of the sight glass height in relation to required oil levels in the bearing housing.

Final System Testing

On November 10, the licensee performed several test runs of the Unit 2 TDAFW pump. These tests involved over four hours of running the pump, including a two hour continuous run at rated speed. No further oil level problems were observed.

Ultrasonic testing of the drain line after installation of the outboard housing drain line vent verified that no void formations were occurring. The inspectors observed ultrasonic testing of the drain lines, oil levels, and appearance of the oil in the sight glass during the final pump testing and concluded that the licensee had adequately modified the turbine oil system to prevent recurrence of the subject problem.

Conclusions

The inspectors reviewed the modifications the licensee implemented to the TDAFW pump during the outage to determine if any of the changes could have resulted in the subject oil system problem. None of the outage modifications appeared to have directly resulted in the oil fluctuation problem based on observations of the licensee's troubleshooting process. The inspectors concluded that some modifications, such as the replacement of the EGR which incorporated a slightly larger pilot valve, may have been contributing factors to the current identification of the problem. However, these types of changes likely resulted in the oil fluctuations occurring sooner, within the established pump testing durations. The licensee had not completed their final root cause determination by the end of the inspection period.

The inspectors concluded that the licensee's troubleshooting activities were performed in an appropriate manner. Observations of maintenance, surveillance, and associated modifications with this issue concluded that increased management attention was focused on the problem and system engineering involvement was good. Based on the final testing performed, the inspectors concluded that the licensee's resolution to the problem should preclude future recurrence. The inspectors also concluded that the phenomenon of air voiding in the oil system was time dependent, which raised questions regarding the duration of previous test conditions for

these types of pump turbines. Routine surveillance may not have been of sufficient duration to identify the problem. Factors such as pump speed, oil system configuration, and oil system pressure each could potentially affect when this adverse condition would occur. As of the end of the inspection period, the NRC had developed generic Information Notice 94-84 on this issue to alert other licensees to the subject problem.

On November 14, 1994, the licensee implemented similar modifications to the Unit 1 TDAFW pump's turbine oil system based on the identification of the Unit 2 problem. This modification is discussed in the paragraph 4.b.

b. On November 14, 1994 the inspectors monitored activities associated with modification of the Unit 1 Turbine Driven AFW pump. The modification was accomplished based on activities discussed in paragraph 4.a of this report. The modification was accomplished in accordance with DCN M11437A.

The inspectors noted that the modification activity was accomplished in a good manner during the morning of November 14. However, the pump was not returned to operable status until approximately 8:00 pm that evening. The inspectors questioned licensee management about the time required to test the AFW pump after completion of the modification. The licensee provided a time line which indicated that procedure revisions necessitated by emerging issues caused the modification completion to be delayed several hours.

The inspectors reviewed the completed work package and associated testing documentation. All modifications and testing activities were documented in a good manner.

The inspectors concluded that the licensee implemented the Unit 1 TDAFW pump modification in a timely manner based on corrective actions taken for the Unit 2 TDAFW pump. However, the inspectors considered better field preparations prior to implementation of the modification could have reduced the outage time.

Within the areas inspected, no violations were identified.

5. **SURVEILLANCE OBSERVATIONS** (61726 and 92902)

During the reporting period, the inspectors ascertained, by direct observation of licensee activities, whether surveillance of safety significant systems and components were being conducted in accordance with technical specifications and other requirements. The inspection included a review of the following procedures and observation of surveillance:

a. On November 22, 1994, the inspectors observed the performance of SI-129.2, Emergency Core Cooling Safety Injection Pump 1A-A Quarterly Operability Test, Revision 4. The purpose of the surveillance is to

assess the operational readiness of SI pump 1A-A in accordance with ASME Section XI. The inspectors noted that the personnel performing the surveillance were knowledgeable of the test procedure and had performed similar tests numerous times. The surveillance was satisfactorily completed and met all its acceptance criteria.

The inspectors had one observation regarding SI-129.2. The procedure had three procedure control forms (PCF) attached which indicated that changes had been made to the procedure since its last revision in July, 1992. The oldest of the three PCF's is dated August, 1993. Although the procedure, with the three changes, was legible and did not seem to hinder the person performing it, the inspectors questioned why it was allowed to go for approximately 15 months without a permanent revision being initiated. The inspectors were informed by a member of the technical support staff that the practice of attaching numerous PCF's to a procedure is the accepted practice and that there is not a schedule to periodically revise Section XI procedures. The inspectors believe that numerous PCF's tend to clutter a procedure and make it less user friendly. However, this practice did not affect satisfactory performance for this procedure.

b. On December 1, the inspectors witnessed surveillance testing of the 2B-B EDG in accordance with 2-SI-OPS-082-007.B. One problem was identified during the performance of initiating an idle start (450 RPM). When using the idle start handswitch 2-HS-082-115, the EDG went to rated speed and remained there (900 RPM). Technical support personnel were contacted to evaluate the problem. Based on subsequent witnessing of EDG operation per the established procedure and interviews with operators performing the test, Technical Support personnel concluded that the problem existed in the idle start circuitry and could not affect the start circuitry associated with an emergency start. The inspectors discussed the basis for this conclusion with Technical Support personnel. The inspectors questioned whether recent modifications incorporated on the 2B-B EDG to correct similar idle start problems had been effective in preventing the problem. Based on review of the circuitry, it was determined that the current problem, although similar, was different since it occurred in circuitry not affected by the recent modifications. The licensee initiated a priority 3 WR (C245683) to troubleshoot the problem during the next scheduled 2B-B EDG outage.

The inspectors verified that the SI was accomplished in accordance with the established procedure and that appropriate inspections of the EDG while in operation were conducted. The inspectors identified to the operator performing the test a small sight glass oil leak on a 2B-2 engine governor connection line. No other problems which could affect operability were identified. The inspectors concluded that the SI was performed in a satisfactory manner.

Within the areas inspected, no violations were identified.

6. **ONSITE ENGINEERING** (37551 and 92903)

During the reporting period, the inspectors conducted periodic engineering evaluations for regional assessment of the effectiveness of the onsite engineering staff. The inspection included a review of the following activities:

a. Modification to TDAFW Level Control Valves

During U2C6, the licensee implemented DCN M09198 to change the existing turbine driven auxiliary feedwater level control system. The purpose of the design change was to simplify the existing TDAFW control system per INPO recommendations. The automatic control scheme was replaced and manual operation is now required of the turbine speed and the four steam generator LCV's. Following the modification, the LCV's are either fully open or fully closed. Upon an TDAFW initiation signal, the LCV's automatically stroke fully open from their normally closed position and remain open until the operator positions the control room handswitch to the close or pull to lock position. The valve, once manually closed, remains closed until all accident signals clear, a new accident signal comes in, or the operator takes manual action. Functionally the new system requires operator action to monitor and maintain steam generator level by varying the speed of the turbine. Handwheels are located on top of the LCV's such that throttling may be performed, if desired. The change also included additional modifications so that AFW can cope with SBO. These changes included high pressure air bottles, pressure regulators, and manual isolation valves added to each of the existing four TDAFW LCV air accumulator tanks to provide sufficient air volume and pressure to close the LCV's at least 4 times during a SBO event.

The inspectors reviewed the DCN package, discussed the modification with the system engineer, walked down portions of the modification, and reviewed the completed PMT associated with the modification. The inspectors also verified that relevant changes were made to the emergency operating procedures and that operators routinely monitor the pressure in the high pressure air bottles. The inspectors concluded that the DCN was appropriately planned and implemented by the licensee.

b. Pipe Break in the Condensate System

On November 29, 1994, at 7:13 a.m., Unit 1 experienced an automatic turbine trip followed immediately by a reactor trip from 100% power. Approximately three hours after the trip, a pipe break occurred in a 14 inch diameter condensate pipe in the turbine building between the 3B and 4B (B train) intermediate feedwater heaters. Operators isolated the leak. Subsequent visual inspection of the exterior of

the pipe revealed a crack approximately 180 degrees around the circumference of the pipe. The failure occurred in a temporary section of pipe that had been installed for flow measurements during turbine generator acceptance testing many years ago. The temporary piping section contained 3 flow straighteners and a flow nozzle. The A and C trains were verified to have the same pipe configuration. The licensee removed the temporary piping sections for all three Unit 1 condensate trains on November 30, 1994. Visual inspection of the pipe failure indicated localized thinning at the interface between the pipe and the second flow straightener plate. All three trains exhibited thinning at the pipe-flow straightener interfaces. This thinning is characterized as flow-accelerated erosion. Unit 2 operated at power during this period. The inspectors verified that the Unit 2 condensate trains did not have this configuration.

Specialist inspectors from Region II conducted a preliminary evaluation of this event at Sequoyah. The preliminary evaluation of the cracked pipe suggests that it failed due to localized erosion, caused by the bypass jetting action of condensate in the space or interface between the outside diameter of the flow straightener plates and the inside diameter of parent pipe. A total of three pipes in this system contained this device. One failed, a second was severely affected and the third showed minor wear in a limited area.

The flow straighteners are a part of a temporary flow metering device and are positioned on the inlet end of the device and secured by the flange connection. The assembly was designed to be used in the condensate system as a temporary flow metering device for turbine performance testing. The straightener is a cylindrical assembly made up of three circular drilled plates interconnected by four 1/2 inch diameter rods. The plates are approximately 13¼ inch diameter and about 3/8 inch thick. The spacing between the three plates is approximately 13¼ inches. Small drilled holes about 3/8 inch diameter cover the plate surface.

As previously stated, the localized wall thinning occurred at the interfaces of the two downstream straightener plates which fit into the inside diameter of the pipe; the third plate is located at the pipe flange connection, which secures the straightener assembly in place. The affected area is a narrow band on the inside diameter surface of the parent pipe. It is approximately 1/2 inch wide and extends over the entire pipe circumference. The through-wall crack, which extended about 180° was centered in an externally machined groove that was approximately three inches wide and 0.125 inch deep. Ultrasonic thickness measurements taken after the failure indicated that the pipe was approximately 0.050 inch thick in the vicinity of the crack, but as much as 0.270 inch just beyond the crack circumferentially and, over 0.320 inch on either side of the crack axially. Through discussion with cognizant licensee personnel, the inspectors ascertained that the machining on the outside diameter of

the pipe was for trueing the outside diameter of the pipe to permit precise machining of the inside diameter, required for metering flows.

The metering assemblies were made up of three pipe sections (two reducers and a 14 inch diameter segment) with flange connections, a flow straightener and a flow nozzle. The failed pipe was made from low carbon, mild steel material believed to be A106 type and measured 14 inch diameter. A review of the available Westinghouse drawing, No. 794D821, disclosed the assembly was manufactured by the Westinghouse Steam Division of Lester, Pa., now closed. The drawing provided no further information, except that it referenced other drawings where additional information could be obtained. A review of licensee drawings revealed that the pipe material upstream and downstream of the subject assembly was made of similar seamless carbon steel type A106 Grade B, Schedule 40 material.

The licensee plans to perform a metallurgical investigation to determine more precisely the root cause of the failure and will provide the inspectors a copy of the report for review.

The inspectors evaluated the installation of the replacement condensate piping. The feedwater condensate system is non-safety, TVA Class H system, which was designed and constructed to meet B31.1-67 code requirements.

At the time of this inspection, the licensee had removed the flow nozzle pipe assemblies from each of the three condensate lines. The assemblies were being replaced with 16 inch diameter straight sections of similar material made of A106 Grade B, Schedule 40 black piping. The new piping was being welded into place utilizing detail welding procedure specification, GT-SM11-0-1N, Rev. 1. Hold points requiring QC inspection included weld joint fitup and visual inspection of the completed welds. The inspectors observed the completed welds on lines "A" and "B" for workmanship, bead height and uniformity, undercut, spatter and cleanliness. The final visual inspection by QC would be performed later following final clean-up grinding. This work was being performed under Work Request No. C265067 and Work Order No. 94-10282-00. Design Change Notice #R-11459-A dated November 30, 1994, was issued to evaluate configuration changes resulting from this pipe replacement. Results of this evaluation indicated that it was acceptable from the standpoint of vibration. By review of the safety assessment report, the inspectors ascertained that the failed pipe section was not located near any safety related equipment, nor did it affect any safety related equipment. The subject piping was non-safety related and non-seismic, hence it was supported for dead weight only. The associated hangers would be analyzed for the resulting weight change. An inservice leak inspection would be performed at operating pressure and temperature to verify the integrity of the new pipe and associated welds. FSAR Figure 10.4.2-1, flow print 1,

2-47W804-1 will be changed to delete a reference to the temporary metering section.

The inspectors reviewed the E/C program relative to the failed piping to determine if the piping was in the program and why the program did not identify the thinned piping before the failure occurred. The following summarizes the results of this review:

- As noted above all three condensate trains on Unit 1 contained the flow metering devices consisting of a 14 inch diameter section of piping, which contained reducers, a flow straightener, and a flow nozzle. In addition, the same flow metering device was installed in two areas in the heater drain system (the flow straighteners had been removed from the heater drain lines during a recent outage).

- Review of E/C Program National Valve and Manufacturing Co. (NAVCO) original fabrication isometric drawing 7121, which identified the components in the program for the Condensate lines in question, revealed that all three lines (trains) containing the flow metering devices were in the E/C program and were modeled with CHECMATE. However, the drawings indicated that the metering devices were temporary. Discussions with plant personnel revealed that Operations personnel and Engineering personnel were aware that the flow metering devices were installed and the devices had been used until recently when ultrasonic flow measuring was initiated. Plans were to remove the metering devices during the next outage. Since the E/C personnel were not aware that the flow metering devices were installed and the drawing indicated the devices were temporary, the E/C personnel did not check to verify that the metering devices had been removed, and modeled the piping as straight sections, not taking into account the metering devices.

  This indicates some weakness in communications since two plant groups knew the devices were installed and being used and this information was not known to the E/C personnel. Also the drawing needed clarification, in that, it would lead you to think that the flow metering devices were temporary and not installed.

  After the pipe failure, the CHECMATE model for the condensate lines was re-analyzed including the flow metering devices. The CHECMATE model does not provide for modeling the flow straighteners, but the analysis indicated a high ranking for wear down stream of the flow nozzle. Therefore, had the E/C personnel known the metering devices were installed, the area of piping that failed (the area of the straighteners) may not have been inspected. If the area had been inspected, the band of erosion was so narrow, it could have been missed since the inspection points are only at grid intersections.

- Review of E/C Program NAVCO drawing 7221 for the Heater Drain piping containing the metering devices revealed that the two lines were in the E/C program, but were modeled as straight sections of piping. For these two locations the drawings are clearer than the drawings for the Condensate lines; that the devices were more than temporary. It is not clear why the E/C personnel did not model the flow nozzle in these sections of piping. The inspectors reviewed thickness measurement data for the piping downstream of the nozzle and in the flow straightener area, which revealed little, if any, wear. The grid pattern and scanning pattern used for the thickness measurements should be sufficient to identify any wall thinning. As noted above, the flow straighteners had been previously removed. TVA plans to leave this piping in service.

The inspectors reviewed licensee actions performed to determine if other areas of flow disturbance had been omitted from the E/C monitoring and inspection program. For this effort, TVA reviewed all NAVCO original fabrication isometric drawings for susceptible systems as well as the latest piping layout (physical) drawings for these systems. The review was performed to identify any flow disturbance components that could affect the E/C program. From this review, approximately 15 areas were identified where some flow disturbing device was installed, or the drawings indicated a location for a device. In all of these cases, the device had been included in the E/C program, was not installed, or was in a portion of the system that was not susceptible to E/C.

The licensee also reviewed all Design Change Requests (DCRs) relative to the turbine performance testing to determine if other flow disturbing devices may have been installed. None was identified.

The inspectors found that the licensee had performed adequate corrective actions to determine the cause and extent of this problem. The findings were preliminary and the licensee had not issued their investigation report. The inspectors noted the following areas that warrant additional attention.

- The fact that the Operations and Engineering personnel were aware of the installed flow metering devices and the E/C personnel were not indicates a possible communications problem.

- The existence of the installed flow metering devices with the drawing indicating a temporary device raises questions about Balance of Plant equipment configuration drawings.

- The fact that E/C personnel did not model the components of the metering devices in the heater drain piping, even though

the drawing indicated the devices were present, indicates some question about the thoroughness of the E/C reviews.

The inspectors concluded that licensee corrective actions for the pipe break event were adequate to reasonably assure system integrity and provided additional information regarding the failure mechanism which should be factored into their erosion/corrosion monitoring program. However, additional management attention should be focused on areas including communications between E/C personnel and other departments, BOP equipment configuration drawings, and thoroughness of erosion/corrosion reviews.

Within the areas inspected, no violations were identified.

7. **PLANT SUPPORT** (71750 and 92904)

During the reporting period, the inspectors conducted reviews to ensure that selected activities of the following licensee programs are implemented in conformance with the facility policies and procedures and in compliance with regulatory requirements.

a. Radiological Effluent, Waste Treatment, and Environmental Monitoring

During this period, the inspectors reviewed selected licensee activities associated with the licensee's environmental monitoring program at Sequoyah. Focus was placed on leakage of diesel fuel oil at Sequoyah during the past three years. The licensee provided information for three reportable spills of oil in 1992. One of these spills was related to underground leakage of auxiliary boiler pipelines. Licensee corrective actions for these leaks included repair of the lines. In addition, extraction wells were installed to remove the oil from the ground. The inspectors were aware of these leaks during the 1992 period and monitored licensee actions to repair the lines at that time.

The other leaks were identified as an oil drip pan spill of approximately 1 gallon at the ERCW pump station and an overflow of a 55 gallon barrel due to rainwater filling the barrel and causing approximately a one gallon spill. Both spills had corrective actions implemented to prevent recurrence. No other reportable spills were identified through November 21, 1994. The inspectors concluded that the licensee was taking necessary actions to minimize oil spills and protect the environment.

b. Cold Weather Preparations

During the inspection period , the inspectors reviewed the status of the licensee's freeze protection program implemented to protect safety-related systems against extreme cold weather. Periodic Instruction 0-PI-OPS-000-006.0, FREEZE PROTECTION, Revision 4, which implements the licensee's program, contains various Appendices, each

being performed at a specified frequency (once per cold weather season, monthly, and weekly) between the period October 1 through March 31. The licensee's program incorporates testing of heat trace and cabinet heaters of critical components associated with feedwater flow, CST, and RWST transmitters. The inspectors reviewed the completed one time performance section of O-PI-OPS-000-006.0 and concluded that the procedure was adequately performed as written. The inspectors performed walkdowns of various components and temporary enclosures for vulnerable areas and did not identify any operability concerns. In addition, the inspectors also reviewed the November 14 performance of the weekly checklist contained in O-PI-OPS-000-006.0. One minor area in the procedure which may require clarification was identified regarding freeze protection measures required by Appendix G. As an example, operator actions in the steam valve vault rooms in MODES 5 and 6 are dependent on outside temperatures being less than 35 degrees Fahrenheit. However, the procedure does not specify that if outside temperatures are forecast to be less than 35 degrees Fahrenheit, the action should still be performed.

The inspectors concluded that although outstanding deficiencies existed on the one time and weekly performances, the inspectors considered that proper prioritization was placed on resolution of the issues. Management sensitivity, to incorporate freeze protection measures before adverse weather was expected, was noted. The inspectors also concluded that the licensee's freeze protection procedures were much improved as compared to previous years. Earlier procedures were cumbersome and difficult to perform within the required time frame. This had resulted in a large deficiency backlog and poor prioritization of deficiency corrective actions. The current process incorporates weekly checklists which enables the licensee to perform frequent checks on the more important freeze protection equipment.

Within the areas inspected, no violations were identified.

8. **EFFECTIVENESS OF LICENSEE CONTROLS IN IDENTIFYING, RESOLVING, AND PREVENTING PROBLEMS** (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.

On December 2, 1994, the inspectors attended the PORC which was convened to discuss the Unit 1 Post Trip Report for the trip which occurred on November 29, 1994, and to discuss Unit 1 restart issues. The post trip review concluded that the immediate cause of the trip was the loss of both 48VDC EHC power supplies due to an electrical spike on the power supply output. The power supply output overvoltage protection limiter setting for both power supplies had been reduced from approximately 52.8 volts to approximately 49.3 volts in December 1993 based upon verbal communication

from an onsite vendor representative. The cause of this event was determined to be an inadequate technical review in changing of the EHC overvoltage trip point. A contributing factor to this event was an increase in radio frequency interference resulting in the overvoltage trip point being exceeded causing the loss of EHC power supply. The PORC identified approximately 25 items which were considered restart items to be resolved prior to restart.

The inspectors reviewed the trip report and those items identified as restart issues. The trip report was thorough and the inspectors concluded that the restart issues covered appropriate areas of inspectors' concerns. The inspectors noted that PORC members were not provided handouts listing the restart issues which seemed to hinder discussion of those issues. Otherwise, the PORC was thorough in conducting the business related to trip and restart.

Within the areas inspected, no violations were identified.

9. **LICENSEE EVENT REPORT REVIEW** (92700)

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

(Closed) LER 328/94-08, Manual Actuation of the Reactor Trip Breakers as a Result of a Malfunction of a Rod Control Demand Step Counter. The issue involved operators opening of the reactor trip breakers on Unit 2 as required by TS when group demand step counters are not providing demand position of control rods within plus or minus two steps. The immediate corrective action was the opening of the reactor trip breakers. Additional corrective actions included functional testing of the step counter and implementation of a more deliberate method to verify the step counter proper operation prior to pulling rods. The inspectors reviewed the associated procedures and determined these corrective actions had been implemented.

Within the areas inspected, no violations were identified.

10. **EXIT INTERVIEW**

The inspection scope and results were summarized on December 5 and 9, 1994 with those individuals identified by an asterisk in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
VIO 327, 328/94-41-01	Failure to follow procedure SSP-12.1 and the inadequacy of procedure FHI-3 during conduct of fuel movement evolutions.

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

Licensee management was informed of the items closed in paragraph 9.

11. Acronyms and Abbreviations

AFW - Auxiliary Feed Water
ASME - American Society of Mechanical Engineers
AUO - Auxiliary Unit Operator
BOP - Balance of Plant
CFR - Code of Federal Regulations
CST - Condensate Storage Tank
DCN - Design Change Notice
DRP - Division of Reactor Projects
EDG - Emergency Diesel Generator
EHC - Electro Hydraulic Control
ERCW - Essential Raw Cooling Water
FHI - Fuel Handling Instruction
FHS - Fuel Handling Supervisor
INPO - Institute of Nuclear Power Operations
LCO - Limiting Condition for Operation
LCV - Level Control Valve
LER - Licensee Event Report
NRC - Nuclear Regulatory Commission
PCF - Procedure Change Form
PER - Problem Evaluation Report
PI - Periodic Instruction
PMT - Post Maintenance Test
PORC - Plant Operation Review Committee
psig - Pounds Per Square Inch Gauge
RWST - Refueling Water Storage Tank
SBO - Station Blackout
SFP - Spent Fuel Pit
SI - Safety Injection
SI - Surveillance Instruction
SOS - Shift Operations Supervisor
SRO - Senior Reactor Operator
SSP - Site Standard Practice
TDAFW - Turbine Driven Auxiliary Feed Water
TS - Technical Specifications
TVA - Tennessee Valley Authority
U2C6 - Unit 2 Cycle 6 Refueling Outage
VDC - Voltage-Direct Current
VIO - Violation

WO - Work Order
WR - Work Request