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

Report Nos.: 50-327/95-26 and 50-328/95-26

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 25, 1995, through January 6, 1996

Lead Inspector: W. E. Holland 1-24-96
W. E. Holland, Senior Resident Inspector Date Signed

Inspectors: R. D. Starkey, Resident Inspector
D. A. Seymour, Resident Inspector
S. E. Sparks, Project Engineer, Paragraph 3.3
C. F. Smith, Reactor Inspector, Paragraphs 4.2 and 5.1
D. E. LaBarge, Senior Project Manager, NRR, Paragraph 4.1

Approved by: [signature] 1/30/96
Mark S. Lesser, Chief Date Signed
Reactor Projects Branch 6
Division of Reactor Projects

SUMMARY

Scope:

Inspections were conducted by the resident and/or regional inspectors in the areas of plant operations, maintenance observations, engineering, and plant support. During the performance of this inspection, the resident inspectors conducted several reviews of the licensee's backshift and weekend activities at the plant.

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Results:

<u>Plant Operations</u> - Operations performance was mixed during this period. One violation with three examples was identified for failure to follow procedures involving boric acid injection using the auxiliary feedwater system, failure to follow administrative requirements during dilution evolutions, and failure to take required actions during abnormal room temperature conditions (paragraphs 2.2.6 and 3.3). However, good operator performance was noted during response to several plant transients and reactor trip events (paragraphs 2.2.1, 2.2.2, 2.2.4, and 2.2.5). Also, operations conducted routine technical specification surveillances associated with reactor coolant system leak rate determinations in a good manner, and appropriate investigations were conducted when a upward trend in leakage was observed (paragraph 3.5.2) In addition, Plant Operations Review Committee reviews of post trip reports was good. However, areas which could be improved during the reviews included better disposition of items which may not be repaired prior to operation and better documentation of guidance for operation with degraded conditions (paragraph 2.4).

<u>Maintenance</u> - Maintenance performance was adequate during this period. One violation was identified for failure to follow procedure during troubleshooting of an annunciator problem resulting in a Unit 1 transient (paragraph 3.1). In addition, balance of plant material condition problems resulted in three unit transients, including two manual reactor trips (paragraphs 2.2.1, 2.2.2, and 2.2.5). Also, a lack of a questioning attitude was observed among electricians performing breaker maintenance when confronted with conflicting information regarding breaker replacement parts (paragraph 3.1). In addition, a weakness in the licensee's freeze protection program was noted, along with a lack of appropriate sensitivity to ensuring that a deficiency associated with freezing was corrected promptly (prior to refreezing) once it was identified (paragraph 3.2). A non-cited violation was identified for failure to establish adequate surveillance procedures for safety-related equipment as required by TS 6.8.1 (paragraph 3.5.1).

<u>Engineering</u> - Engineering performance was mixed during this period. Good performance was observed during review of the change to the Sequoyah 10 CFR 50.59 Requirement Implementation Process. Review of two design change packages indicated that high quality reviews were conducted which show the effectiveness of the safety analysis procedure (paragraph 4.1). However, other areas showed weaker performance. Examples were a weakness in the material procurement process which allowed incorrect breaker parts to be identified for type DS-532 breakers (paragraph 3.1.2); a review of a low oil level condition on Unit 2 main bank transformers by the customer group on December 23, 1995, was not conservative, resulting in an unnecessary automatic turbine trip (paragraph 3.4); and an observation regarding a lack of documentation of a thorough evaluation for the failures experienced in the Unit 1 blowdown lines on December 28, 1995, and subsequent interim corrective actions to the system prior to returning the system to service (paragraph 4.3).

Plant Support - Performance in the Security area was considered good regarding implementation of compensatory measures as required by the Security Plan after a power failure of the security system. However, the failure of both the emergency and battery backup portions of the relatively new system indicated additional management focus was necessary to address the issues (paragraph 5.1).

REPORT DETAILS

Acronyms used in this report are defined in paragraph 8.

1.0 PERSONS CONTACTED

Licensee Employees

Adney, R., Site Vice President
*Baumstark, J., Plant Manager
*Brock, D., Maintenance Manager
Bryant, L., Outage Manager
*Burzynski, M., Engineering & Materials Manager
*Cooper, M., Technical Support Manager
*Driscoll, D., Nuclear Assurance & Licensing Manager
*Fink, F., Business and Work Performance Manager
*Flippo, T., Site Support Manager
*Enterline, G., Operations Manager
*Kent, C.,Radcon/Chemistry Manager
*Meade, K., Compliance Manager
*Poage, L., Site Quality Assurance Manager
*Rausch, R., Maintenance and Modifications Manager
Robertson, J., Independent Analysis Manager
*Shell, R., Site Licensing Manager
*Smith, J., Regulatory Licensing Manager
Summy, J., Assistant Plant Manager

NRC Employees

*Holland, W., Senior Resident Inspector
*Seymour, D., Resident Inspector
*Starkey, R., Resident Inspector
*Sparks, S, Project Engineer

* Attended exit interview.

Other licensee employees contacted included operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

On December 4, 1995, Mr. J. S. Summy became the Sequoyah Assistant Plant Manager. Mr. Summy reports to the Plant Manager and has the Technical Support and Outage organizations as focus areas.

2.0 PLANT OPERATIONS (71707 and 92901)

2.1 PLANT STATUS

Unit 1 began the inspection period in power operation. The unit operated at power until November 27, 1995, when the turbine generator was taken off-line due to a ground condition in the generator exciter.

This event is further discussed in paragraph 2.2.1. The unit reconnected to the grid on November 30, 1995, and operated at power until December 8, 1995, when the unit was manually tripped by operators due to a failure of an air line to the #4 FRV. This event is further discussed in paragraph 2.2.2. After repairs were accomplished, the unit was taken critical on December 10, 1995, and reconnected to the grid later the same day. Unit 1 operated at power until December 25, 1995, when the unit was manually tripped by operators due to loss of control of the main generator excitation system. This event is further discussed in paragraph 2.2.5. After repairs were accomplished, Unit 1 was taken critical on January 1, 1996, and reconnected to the grid on January 2, 1996. Unit 1 operated at power until January 6, 1996, when the turbine was taken off line for balancing. After balancing was accomplished, Unit 1 was reconnected to the grid later the same day. The unit operated at power for the remainder of the inspection period.

Unit 2 began the inspection period in power operation. The unit operated at power until December 21, 1995, when the unit was manually tripped by operators due to increasing condenser pressure. This event is further discussed in paragraph 2.2.4. Unit 2 was restarted on December 22, 1995, and reconnected to the grid on December 23. Approximately ½ hour later the turbine tripped due to a "B" phase main bank transformer low oil level. This issue is further discussed in paragraph 3.4. Oil was added to the transformer and the unit was reconnected to the grid on December 24, 1995. The unit operated at power for the remainder of the inspection period.

2.2 DAILY INSPECTIONS

The inspectors conducted selective examinations, on a day-to-day basis which involved control room tours, plant tours, and management meetings. The following activities were specifically reviewed:

2.2.1 UNIT 1 POWER REDUCTION

On November 27, 1995, Unit 1, while operating at full power, experienced a intermittent ground condition on the main generator exciter. At approximately 1:40 p.m., operators noticed that several control room instrument indications were fluctuating. Personnel were dispatched to the turbine building to evaluate secondary plant performance and look for the source of the problem. At this time, personnel observed arcing inside the generator exciter cubicle. After a visual inspection of the exciter cubicle by maintenance and engineering personnel, the decision was made to reduce turbine load and take the generator off-line. At 3:12 p.m. Unit 1 commenced an emergency shutdown. During this same time period, the site fire alarm was sounded, as a precautionary measure, to ensure that the fire brigade was in standby readiness. At 3:20 p.m., the SOS declared a NOUE due to the degradation of plant conditions. At 3:27 p.m., with the unit less than 50% power, operators manually tripped the turbine, and continued to reduce reactor power to less than 5%. At 3:39 p.m., the NOUE was terminated when operators opened the exciter field breaker and control room indication fluctuations stopped.

The inspectors noted that operators were deliberate in discussing changing plant conditions during the shutdown and in using appropriate procedures. A crew brief was held prior to starting the shutdown and again before tripping the turbine. The inspectors concluded that operators performed the unplanned unit shutdown in a good manner.

Following the shutdown, the licensee formed an event investigation team to evaluate the problem. Preliminary licensee inspections identified a cable in the exciter cabinet from the PMG to the exciter was grounded resulting in the arcing condition. Over the next 3 days, the licensee replaced the faulty cable and conducted inspections and testing for other problems. An exciter stator pole ground condition was found and repaired. Unit 2, which was operating at full power, was also inspected for the cable configuration which caused the Unit 1 problem. Cable configuration on Unit 2 was determined to be acceptable.

On November 28, 1995, the inspectors were briefed by technical support management on the action plan to address the Unit 1 problem. The plan included: cable repair, checkout of the Unit 1 exciter for any other internal potential problems, testing of the Unit 1 voltage regulator to ensure no damage was caused by the arcing of the exciter, and testing of selected instrument loops to evaluate the instrumentation condition based on the fluctuations observed. On November 29, the event investigation team briefed licensee management on their conclusions and recommended corrective actions for the event. An additional briefing of NRC inspectors was provided on November 30, 1995.

The inspectors reviewed licensee briefing documentation for the event, operator logs for the event time frame, and disposition documents for corrective actions required prior to restart. The inspectors noted that Unit Operator logs for the event were not as clear as logs maintained by the Unit 1 ASOS or the SOS. The inspectors also reviewed the significance of the instrumentation fluctuations and determined that safety-related instruments had not been affected. The licensee determined that the exciter arcing caused radio frequency interferences, which caused the instrument fluctuations.

The inspectors concluded that operator response to the event was good, with the exception of unit operator log entries. In addition, the event investigation and corrective actions prior to restart were good; however, the event was another example of BOP material condition problems continuing to challenge plant operations.

2.2.2 UNIT 1 REACTOR TRIP

On December 8, 1995, at 9:56 p.m., a manual reactor trip was initiated by operators on Unit 1 due to a loss of level control on SG #4. The cause of loss of level control was a broken fitting on the control air supply line to the #4 FRV. Operators initially reacted to the loss of level control by dispatching AUOs to the FRV. The operators identified the air line failure and took immediate actions to reestablish control air supply by holding the line in place. However, a temporary repair could not be accomplished and operators tripped the reactor prior to SG level reaching a point where an automatic trip would have initiated.

The inspector responded to the plant and reviewed unit status and operator response to the event. The inspector considered that operator response was very good. The inspector reviewed the licensee's activities associated with corrective actions prior to Unit 1 restart. Corrective actions reviewed included air line replacement for the Unit 1 FRVs, inspection of Unit 1, #2 RCP motor coolers for flow degradation, and repair to the low pressure heater drain tank level control valve. All corrective actions appeared to address the degraded conditions.

The inspector concluded that operator response to the event was good. In addition, the post trip review and corrective actions prior to restart were good. However, the event was another example of BOP material condition problems continuing to challenge plant operations, and in this case, challenging safety systems.

2.2.3 UNIT 2 REACTOR COOLANT PUMP #2 INCREASED SEAL LEAKAGE

On December 10, 1995, the inspector learned of a condition associated with increased leakage past the Unit 2, RCP #2, #1 seal. The leakage increased to approximately 6.25 gpm over a 12 hour period. Annunciation for high seal leakoff was set at 4.8 gpm. In addition, AOP-R.04, REACTOR COOLANT PUMP MALFUNCTIONS, Revision 1, required operator actions to initiate unit shutdown within 8 hours after seal leakoff flow increased above 5 gpm. The AOP was revised to recognize higher allowable seal leak rates approximately 14 hours after the leakage exceeded 5 gpm.

A special inspection was conducted for this event. The inspection results were discussed in Inspection Report 327, 328/95-27.

2.2.4 UNIT 2 REACTOR TRIP

On December 21, 1995, at 6:27 a.m., Unit 2 was manually tripped by operators from approximately 100% power. The reactor trip was initiated when operators observed condenser pressure rising above the turbine trip setpoint due to loss of three condenser circulating water pumps. The condenser circulating water pumps tripped due to a fault condition in the 161 kV switchyard. The fault condition was caused by a failure of PCB 974, which caused a voltage drop in the 161 kV switchyard for approximately 5 cycles until the fault was cleared by other breakers opening. Review of this failure is further discussed in paragraph 4.2 of this report. Also, as a result of the switchyard voltage drop, normal power to several plant security systems was lost. In addition, backup power for these systems also failed. This problem is further discussed in paragraph 5.1 of this report.

The inspector responded to the plant and reviewed unit status and operator response to the event. The inspector considered that operator response was very good. In addition, a region based inspector was dispatched to support the residents in review of electrical issues. The inspectors reviewed the licensee's activities associated with corrective actions prior to Unit 2 restart and considered them to be good.

The inspectors concluded that operator response to the event was good. In addition, the post trip review and corrective actions prior to restart were good. However, the event was an example of a plant component failure challenging plant operations and safety systems.

2.2.5 UNIT 1 REACTOR TRIP

On December 25, 1995, at 7:13 a.m., a manual reactor trip was initiated by operators on Unit 1 due to a loss of control of the main turbine generator excitation system. The cause of loss of excitation control was determined to be a ground condition on one or more exciter field poles.

The inspector responded to the plant and reviewed unit status and operator response to the event. The inspector considered that operator response was very good. The inspectors reviewed the licensee's activities associated with corrective actions prior to Unit 1 restart. Corrective actions included replacement of the Unit 1 turbine generator exciter and refurbishment of the generator voltage regulator.

The inspector concluded that operator response to the event was good. In addition, the post trip review and corrective actions prior to restart were satisfactory. However, the event was another example of BOP material condition problems continuing to challenge plant operations and safety systems and similar to the exciter failure of November 27 discussed in paragraph 2.2.1.

2.2.6 OPERATIONAL ISSUES IDENTIFIED BY IPAP

During this period, the inspectors reviewed two issues associated with operational evolutions. These issues were identified during an IPAP inspection conducted early in the inspection period (paragraph 6).

2.2.6.1 ABNORMAL PRESSURIZATION OF UNIT 1 AFW SYSTEM

On November 29, 1995, operations attempted to inject boric acid into the Unit 1 steam generators using the AFW system flowpath. This evolution was being accomplished in accordance with 0-SO-36-3, SECONDARY SYSTEM BORIC ACID INJECTION, Revision 7. During the injection of chemicals in accordance with procedure, operators observed an AFW system over pressure alarm. Subsequent reviews indicated the over pressure condition resulted from operation of the boric acid injection pump with the AFW level control valves shut (AFW system not in operation).

The inspectors reviewed 0-SO-36-3 and noted that Precaution and Limitation step 3.0.F required an AFW pump to be in service during boric acid injections to the steam generators. On November 29, 1995, dayshift operations personnel attempted to inject boric acid to the Unit 1 Steam

Generators without the AFW system being in operation. This condition resulted in portions of the AFW system being subjected to higher than normal pressure (approximately 1650 psig). Failure to follow 0-SO-36-3 is identified as VIO 327, 328/95-26-01.

After the event, the licensee wrote PER SQ952167PER. The inspector reviewed the initial actions for the PER and determined that an evaluation was conducted which concluded the structural integrity of the affected piping was maintained.

2.2.6.2 CONDUCT OF DILUTION EVOLUTIONS ON UNIT 1

On November 30, and December 1, 1995, an IPAP inspector observed operators conducting dilution evolutions on Unit 1. The inspector observed these evolutions being performed without the use of a procedure. The inspector questioned this practice and was informed that SSP-2.51, RULES OF PROCEDURE USE, Revision 5, governed procedure usage in this case. The inspector reviewed SSP-2.51 and noted that Section 2.2.2.A required continuous use procedures be present and directly referred to during the performance of work steps. The inspector subsequently determined that the continuous use procedure for dilution evolutions was 0-SO-62-7, BORON CONCENTRATION CONTROL, Revision 2. 0-SO-62-7 was not present nor directly referred to at all times during the dilution evolutions observed. Failure to follow the requirements of SSP-2.51 is identified as an additional example of VIO 327, 328/95-26-01.

The licensee wrote PER SQ952194PER on December 4, 1995, to address this issue. Immediate corrective actions included operations department briefings regarding SSP-2.51 requirements.

2.3 MONTHLY INSPECTIONS

On November 28, 1995, the inspectors selected two safety-related tagouts in effect and ensured that the tagouts were properly prepared and implemented by verifying correct placement of tags on breakers, switches, and valves. The inspectors also observed that the tagged components were in the required positions. The two tagouts reviewed and walked down were 1-HO-95-2434, ERCW R-A pump, and 0-HO-95-4240, 2A-A High Pressure Fire Pump. The inspectors concluded that the two tagouts were correctly prepared and placed.

2.4 EFFECTIVENESS OF LICENSEE CONTROLS

During this period, the inspector observed and evaluated the effectiveness of selected PORC meetings.

2.4.1 REVIEW OF PORC FOR UNIT 2 TRIP REPORT

On December 21, 1995, the inspectors observed the licensee's PORC review of the Unit 2 trip report for the trip that was initiated on

December 21, 1995. The inspectors noted the presentation addressed restart issues and that the PORC members asked appropriate questions to assure safety focus was maintained. However, several corrective actions prior to restart were not fully dispositioned. For example, one issue involved MSR vent operation. The maintenance corrective action for this issue appeared to have a material restraint at the time of the review. The PORC decided that the final disposition (repair or justify leaving condition as is) needed resolution prior to generator synchronization. However, discussion as to additional operational guidance/restraints without the problem being repaired was not discussed. The inspectors noted the following day that the appropriate repairs were made.

The inspectors concluded the post trip PORC review was good; however, some issues which may have not been physically repaired prior to condition restraints being met were not discussed in a clear, concise manner during the review.

2.4.2 REVIEW OF PORC FOR UNIT 1 TRIP REPORT

On December 29, 1995, the inspectors observed the licensee's PORC review of the Unit 1 trip report for the trip that was initiated on December 25, 1995. The inspectors noted the PORC discussed restart issues that were identified in the post trip report. The inspectors noted that the licensee had not determined the cause of the exciter failure at the time of the meeting. However, the PORC was informed that the corrective actions being implemented (exciter replacement and voltage regulator refurbishment) bounded any failure yet to be determined. In addition, several other issues were discussed. One issue involved leakage of reactor coolant past the #3 seal for the Unit 1, #2 RCP. This leakage was described as a small stream of water directed against the pump vibration probes bracket, running down the side of the pump seal housing to the motor support stand, and draining through permanently installed drain piping. The inspectors asked the licensee if a technical evaluation had been conducted for this condition. The licensee provided an evaluation to the inspectors the next day. The evaluation discussed Unit 1 leakage as being within TS limits and discussed potential boric acid effects due to the leakage on carbon steel components during the current operating cycle. However, the evaluation did not discuss clear compensatory measures to specifically monitor for additional degradation, or actions to be taken. The evaluation recommended operation with the current leakage to management. Management accepted the recommendation. The inspectors reviewed the technical evaluation and considered that clear guidance for operation with the degraded condition was not documented. The inspectors subsequently determined that the licensee was monitoring the leakage with video cameras on a weekly basis to evaluate for additional degradation during operation.

The inspectors concluded that the post-trip PORC review was satisfactory; however, clear guidance for operation with a degraded condition associated with RCP seal leakage was not documented in the evaluation.

2.5 LICENSEE NRC NOTIFICATIONS

On November 27, 1995, the licensee made a call to the NRC as required by 10 CFR 50.72. The issue involved entry into the site emergency plan (NOUE) due to SOS judgement that events were in progress which indicated an actual or potential degradation of the level of safety to the plant. The entry was associated with the Unit 1 turbine generator shutdown discussed in paragraph 2.2.1.

On December 8, 1995, the licensee made a call to the NRC as required by 10 CFR 50.72. The issue involved initiation of a manual reactor trip on Unit 1, which was operating at 100% power. The trip was initiated due to loss of level control on SG #4. This event is further discussed in paragraph 2.2.2.

On December 21, 1995, the licensee made a call to the NRC as required by 10 CFR 50.72. The issue involved initiation of a manual reactor trip on Unit 2, which was operating at 100% power. The trip was initiated due to condenser vacuum rising above the turbine trip setpoint. This event is further discussed in paragraph 2.2.4.

On December 25, 1995, the licensee made a call to the NRC as required by 10 CFR 50.72. The issue involved initiation of a manual reactor trip on Unit 1, which was operating at 100% power. The trip was initiated due to a loss of control of the main turbine generator excitation system. The event is further discussed in paragraph 2.2.5.

Within the areas inspected, one violation was identified.

3.0 **MAINTENANCE OBSERVATIONS** (62703, 61726, and 92902)

During the reporting period, the inspectors verified by observations, reviews, and personnel interviews, 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:

3.1 MAINTENANCE ISSUES IDENTIFIED BY IPAP

During this period, the inspectors reviewed two issues associated with maintenance evolutions. These issues were identified during an IPAP inspection conducted early in the inspection period (paragraph 6).

3.1.1 REVIEW OF UNIT 1 UNANTICIPATED POWER INCREASE

On December 5, 1995, Unit 1 experienced an unanticipated power increase to approximately 102% from 100% power when a breaker tripped in a process protection rack during annunciator problem troubleshooting by I&C technicians. During the transient, operators received multiple alarms and control rods were observed stepping out. According to PEDS data, MWT reached 3443 (licensed thermal reactor power is 3411 MWT).

The UO placed rods in manual and stepped them in to their original position and power returned to 100%. During this evolution, charging flow also went to a minimum and all pressurizer heaters started due to pressurizer level deviation. Operators determined that the transient was caused by an incorrectly placed jumper which resulted in a failure of the Tavg program. This failure affected rod control, PZR level control, steam dumps, and a bistable for the Tavg/Tref deviation alarm. The jumper was immediately removed by I&C technicians, a main supply breaker feeding the process protection rack was reclosed, all associated alarms cleared, and the unit was returned to a stable condition. The inspectors determined the power excursion did not approach thermal power safety limits.

The event began when I&C technicians were troubleshooting an annunciator problem on MCR common annunciator panel 0-M27-A. Troubleshooting was performed under WR C211017 in accordance with SSP-6.23, MAINTENANCE MANAGEMENT SYSTEM, TROUBLESHOOTING, Revision 4. The WR was in response to a problem with annunciator window D-4, ERCW 480V MCC 1B-B OR 2B-B UNDERVOLTAGE. When the technician started the troubleshooting process he referred to annunciator response procedure 0-AR-M27A for window D-4 which indicated that the source of input to the annunciator was SER 1058 (sequential event recorder) on Unit 1 and SER 2079 on Unit 2. Since the annunciator is common to both units, the output from the annunciator system is sent to the SER CRT and alarm printer on both units. The alarm is hard wired to Unit 1 (SER 1058) and from there it is "retransmitted" to the Unit 2 SER/alarm printer via fiber optics. There was not a hard wired terminal board point for SER 2079 on Unit 2. SER 2079 was only a data transmission point which was transmitted by fiber optics.

The technician properly located SER point 1058 in the Unit 1 annunciator panel. He then searched Unit 2 annunciator panels but was unable to locate SER point 2079. The technician continued his search for SER point 2079 in the communications room, located in another area of the control building, but again was unable to find SER 2079. He then returned to the control room and looked in Unit 1 annunciator panels and found a point labeled SER 2079 which he assumed to be the correct point. Believing that he had located the correct SER point, he jumpered out the point which resulted in tripping the main supply breaker feeding the Unit 1 process protection rack 1-R-24 and causing the transient.

In reviewing the activity, the inspectors concluded that there were several factors which contributed to causing this event.

- First, the technician missed at least three opportunities prior to the event to identify his mistake of being on the wrong SER point. (1) When he was unable to readily locate SER point 2079 on Unit 2, he could have stopped work and requested assistance. (2) A CRT was available on each unit in an annunciator cabinet from which the technician could have queried the BETA Annunciator System to determine the function of the two SER points in question. Thus, he could have determined that SER 2079 on Unit 1 was not the correct point. (3) The technician checked only for dc voltage, rather than both ac and dc voltage across SER 2079, and noted a reading of 0 Vdc, when actually SER 2079 was supplied by 120 Vac. Since the annunciator system is 125 Vdc, if the technician had also checked for ac voltage, he may have found his mistake in being on the wrong point.

- Second, the technician was troubleshooting from a WR which did not contain supporting documents such as electrical prints or vendor drawings. According to I&C management, this task was considered a routine, skill of the craft task, and as such, if instructions were inadequate, the technician should stop work and get clarification.

- Third, although the technician had received training on the BETA Annunciator System, he had not been trained on the specific feature related to "retransmission" of data. The licensee questioned other I&C technicians and discovered that several technicians did not know about the "retransmission" feature. The inspectors subsequently reviewed the licensee's training lesson plan MTS250.045, BETA ANNUNCIATOR SYSTEM, and confirmed that it did not address the subject of "retransmission".

- Fourth, the labeling on the exterior of the annunciator cabinet, which contained the retransmission modules, was inconsistent with adjacent cabinet labeling in that it did not identify the retransmission SER points located in the cabinet. The actual retransmission modules inside the cabinet were adequately labeled.

- Fifth, there was confusion after the event as to whether the 2 amp fuse found in the system was the correct size. Although there was initially conflicting information regarding the proper fuse size, the licensee concluded that the 2 amp fuse was correct. The licensee also questioned why the main supply breaker to the process protection rack tripped rather than the 2 amp fuse blowing.

The inspectors reviewed SSP-6.23, and determined the process described in SSP for troubleshooting was not followed during the annunciator troubleshooting effort. SSP-6.23, step 5.1.3 [6] required that supervision ensure that personnel are qualified for the troubleshooting activities being performed. Additionally, SSP-6.23, step 5.1.3 [8] required that if at any time the scope of the troubleshooting changes, such that the troubleshooting instructions are no longer valid or are inadequate, ensure the troubleshooting plan is revised. During the maintenance activity, I&C supervision directed personnel who were not fully qualified/trained on the Beta Annunciator System to perform the troubleshooting task. In addition, the technicians encountered problems during the troubleshooting process in identifying the correct SER point, and failed to request assistance and/or have the troubleshooting instructions revised. Failure to follow the requirements of SSP-6.23 is identified as VIO 327, 328/95-26-02.

The inspectors discussed the activity with maintenance management and were informed the management's expectations were for the technicians to stop work whenever a question existed regarding a maintenance activity. The inspectors agreed with maintenance management that the most significant contributing factor to this event was the failure of maintenance personnel to stop work and request assistance.

PER SQ952204PER was written to document this event. One of the corrective actions resulting from PER SQ952204PER was the assignment to the licensee's Operations Design Support Group to perform a fuse and breaker coordination evaluation for "R" panels 14 through 24 in Units 1 and 2, with a corrective action due date of March 15, 1996. The inspectors will review the evaluation's conclusions during a future inspection. This issue is identified as IFI 50-327, 328/95-26-04, Review Fuse and Breaker Coordination Evaluation Performed in Conjunction with PER SQ952204PER.

3.1.2 REVIEW OF PREVENTATIVE MAINTENANCE ON 480-V BREAKER

On December 1, 1995, during performance of preventive maintenance procedure MI-10.5, 480-V WESTINGHOUSE DS SWITCHGEAR INSPECTION, Revision 22, on the normal feeder breaker to shutdown board 1B2-B, electrical maintenance personnel were unable to obtain a trip load force of less than two pounds. Subsequently, on December 2, electricians attempted to replace the breaker operating mechanism with a new operating mechanism from power stores. The breaker being worked was a Westinghouse Type DS-532. The written long description for this type operating mechanism in the TIIC system stated that the particular operating mechanism in power stores would apply to type DS-206, DS-416, and DS-532 breakers. When preparing to order a replacement of the operating mechanism from power stores, the electricians referred to the vendor manual to determine the correct part number for the operating mechanism. The vendor manual identified a different part number than that stated in the TIIC system. An NRC inspector, who was observing the breaker maintenance activity, questioned the electricians on parts applicability. However, the electricians concluded the TIIC information was correct and procured the part from power stores. When the electricians were subsequently unable to make the replacement part function correctly, the breaker component engineer was notified and Westinghouse was contacted. Westinghouse confirmed that the vendor manual was correct and that the incorrect operating mechanism for the DS-532 breaker was listed in the TIIC system. Since the correct replacement part was not available on site, the original operating mechanism was cleaned, adjusted and reinstalled in the breaker. The breaker was then reinstalled as the normal supply breaker in shutdown board 1B2-B, successfully tested, and returned to service.

The licensee initiated PER SQ952213PER to document the discrepancy associated with the incorrect part in power stores. The licensee also initiated a data search to determine if there were breakers in use which had the incorrect operating mechanism installed. One such breaker was identified as the normal feeder breaker on 480 V unit board 2B, which is non-safety related and located in the turbine building. The licensee, after consulting with Westinghouse, determined that the breaker could remain in service with no adverse affect until the next refueling outage at which time the correct operating mechanism would be installed. WR C210985 was written to document the work request.

The inspectors concluded that there was a lack of a questioning attitude among electricians performing the breaker maintenance when confronted with conflicting information regarding breaker replacement parts during this maintenance activity. The inspectors also concluded that, in this instance, there was a weakness in the material procurement process which allowed incorrect breaker parts to be purchased for type DS-532 breakers.

3.2 FREEZE PROTECTION REVIEW

On December 10, 1995, due to cold weather conditions, Unit 1 experienced freezing of feedwater flow transmitter 1-FT-3-90A. The freezing first occurred when Unit 1 was in startup approaching criticality and occurred again later the same day when the unit was at approximately 50% power. The licensee initiated WO 95-14040 to troubleshoot and correct the problem, with electricians and I&C technicians involved in working on the solving the problem. Deficiencies were identified with the heat tracing line, the insulation, and the heat tracing controller. Work was started by electricians on the heat trace line and the insulation during the dayshift on December 10. Once that portion of the work was completed, I&C started work on the heat trace controller but did not complete the work prior to 1-FT-3-90A freezing again later in the evening of December 10. The inspectors were informed by maintenance management that the turnover given I&C failed to stress the urgency of completing the task or that compensatory measures should be put in place if the work was not completed prior to freezing conditions occurring again.

The inspectors concluded that the freezing of the feedwater flow transmitter represented a weakness in the licensee's freeze protection program and that there was a lack of appropriate sensitivity in ensuring that the deficiency was corrected promptly once it was identified or that compensatory measures were established.

3.3 REVIEW OF AUXILIARY INSTRUMENT ROOM POWER SUPPLY/INSTRUMENT FAILURES

During the period, the inspectors reviewed an issue associated with elevated temperatures in the 6.9 kV Shutdown Board rooms, and the ACR. On December 9, 1995, at approximately 8:00 a.m., MCR operators reported that 1-LI-3-173 and 174 drifted low by approximately 10%. These instruments are MCR indicators for the TDAFWP level input from SGs 2 and 1, respectively. Approximately 10:00 a.m., instrument mechanics, in response to the identified problems, discovered high temperatures in the ACR. Temperature in the main area of the ACR was measured to be approximately 89°F. Normal temperature in this area was 75 to 80°F. At approximately 10:30 a.m., MCR operators reported that 1-LIC-3-171 was acting erratic (swapping from auto to manual). This level controller provides control function to the level control valve for SG #4 from the MDAFWPs. At approximately 12:00 noon, licensee personnel identified that a 6.9 kV Shutdown Board Room Chiller was not loaded. Licensee personnel soon corrected this problem which initiated cooling to these areas. At approximately 1:00 p.m., 1-FI-3-155 and 170 failed, which provided flow indication for SGs #2 and 4 AFW inlet flow. At approximately 2:00 p.m., the ACR temperature had been returned to a normal value of 76°F. The licensee initiated a level C PER SQ952233PER for this issue.

The inspectors discussed this issue with licensee personnel, who identified problems during the conduct of procedure 0-PI-OPS-000-606.0, BALANCE OF PLANT TEMPERATURE MONITORING SYSTEM, Revision 13. This procedure required the recording of temperatures from several local temperature indicators (including TI-9 and 18), once per 8 hour shift. The completed procedure noted that TI-9 was located on the Unit 1 side, 6.9 kV Shutdown Board Room 1A-A, while TI-18 was located on the Unit 2 side, "B" Train 6.9 kV Shutdown Board Room. The limits for these TIs as noted in the procedure were less than or equal to 80°F. On December 8, 1995, during the 7:00 a.m., to 3:00 p.m., shift, and during the 3:00 p.m., to 11:00 p.m., shift, temperatures of 80°F and 81°F, respectively, were recorded. Note (2) to TABLE 1 of procedure 0-PI-OPS-000-606.0 states that if temperature for these TIs is greater than or equal to 80°F, perform the actions of Section 6.1 [2]. Section 6.1. [2] of procedure 0-PI-OPS-000-606.0 required that if temperature is greater than 80°F [inconsistent with Note (2)], (a) initiate actions to expeditiously restore the 6900 V Shutdown Board Room temperature to less than 80°F, (b) monitor and record the 6900 V Shutdown Board Room temperature in accordance with Appendix C (which requires hourly temperature monitoring), and (c) if the 6900 V Shutdown Board Room temperature exceeds 104°F, then notify the SOS. A NOTE in Section 6.1 [2] states that the SOS is to be notified the first time a reading is determined out of limits, and again when temperature is determined within limits. A review of control room logs and discussion with the onshift SOS revealed that this notification was not initially made. As such, actions should have been initiated, during the 3:00 p.m., to 11:00 p.m., shift on December 8, 1995, to expeditiously restore the 6.9 kV Shutdown Board Room temperature to less than 80°F, and monitoring and recording the 6900 V Shutdown Board Room temperature in accordance with Appendix C (which requires hourly temperature monitoring) should have begun.

The completed procedure, Appendix B, Table 1, performed on December 8 and 9, 1995, indicates that during the 11:00 p.m., to 7:00 a.m., shift, temperatures continued to increase to 81°F and 82°F, respectively. During the next shift (7:00 a.m., to 3:00 p.m., on December 9), temperature was recorded to be 85°F and 86°F for TI-9 and TI-18, respectively. It was during this shift that the MCR operators identified problems with various instruments. A review of Appendix C of the completed procedure noted that hourly temperature readings began approximately 10:30 a.m., on December 9. By approximately 1:30 p.m., temperatures had decreased to a normal value of less than 80°F.

Based on the above information, the inspector concluded that the licensee failed to follow procedure 0-PI-OPS-000-606.0 by not initiating actions to expeditiously restore the 6900 V Shutdown Board Room temperature to less than 80°F, and failed to take hourly readings once the temperature was measured to be greater than 80°F. Failure to follow this procedure resulted in the failure to identify a problem with a chiller to the 6.9 kV Shutdown Board Rooms and ACR areas, which led to the malfunction and/or failure of various safety related and important to safety instruments. Failure to follow procedure 0-PI-OPS-000-606.0 is identified as an additional example of violation 327, 328/95-26-01.

The inspectors held discussions with licensee personnel regarding the failure mechanism, extent of condition, and actions taken to assure operability of equipment in close proximity. The failed equipment was located in two of four rooms near the ACR. These rooms, along with the 6.9 kV Shutdown Board Rooms and ACR, were cooled by the same chiller package. Licensee personnel noted on the PER that these rooms were noticeably hotter than the ACR, which measured 89°F. The licensee determined that two failed voltage regulators caused two power supplies to fail, with one power supply serving 5 instruments, the other serving 3 instruments. These failures were in addition to the failure of 1-LIC-3-171B. The inspectors discussed the design basis temperature requirements for these rooms and electrical equipment, immediate licensee corrective actions to check other instruments, the listing of equipment affected or potentially affected, and actions to monitor affected instruments in the future. The licensee also determined that the preliminary root cause for the failure of the recently rebuilt 6.9 kV Shutdown Board Room chiller was the setpoint setting of a pressure switch which allowed the chiller to load. This switch was adjusted by the vendor as part of the chiller rebuild warranty, and was not set in the mid-range as was the general practice of the licensee. A setpoint setting at the end of the acceptable range, in conjunction with drift of the pressure switch, caused the chiller to not load upon demand. The licensee was continuing with development of corrective actions when the inspection period ended.

3.4 REVIEW OF UNIT 2 TURBINE GENERATOR TRIP

On December 23, 1995, during Unit 2 startup, operators received a transformer oil level abnormal alarm during testing of the preferred/non-preferred cooler groups for the main bank transformers. Customer group was notified and determined that all Unit 2 main bank transformers had a low level condition, apparently due to the cold weather. However, they also advised operators that the low level alarm condition should clear after the generator was reconnected to the grid. Unit 2 was subsequently connected to the grid at 7:51 p.m., on December 23, 1995. Approximately 30 minutes later, a turbine trip was initiated due to a low oil level condition on the "B" phase main bank transformer. Approximately 80 gallons of oil was added to the transformer after the event.

The inspectors discussed the event with licensee personnel and concluded that operator sensitivity to identification of the low oil level condition was appropriate. However, the review of the condition by customer group was not conservative, resulting in the unnecessary automatic turbine trip.

3.5 SURVEILLANCE REVIEWS

During the reporting period, the inspectors ascertained, by direct observation of licensee activities, whether surveillances 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:

3.5.1 REVIEW OF INSTRUMENT CALIBRATION PROCEDURES

The inspectors recently learned of an issue at Watts Bar concerning the possible incorrect use of TS ESFAS instrumentation "trip setpoint" and "allowable values" when performing instrument calibrations. Several of the values in the Watts Bar TS ESFAS instrumentation table were bounded by "equal to or greater than" symbols or "equal to or less than" symbols. At Watts Bar, these values were considered to be nominal values even though they were bounded by the symbols. The Watts Bar TS "Bases" also refer to the values as nominal. Watts Bar addressed the discrepancy by revising their TS to delete the "symbols" which precede the TS ESFAS values.

Based on the Watts Bar issue, the inspectors reviewed Sequoyah TS 3.3.2.1, Engineered Safety Feature Actuation System Instrumentation, to determine the applicability to Sequoyah of the Watts Bar calibration methodology issue. The inspectors found that the Sequoyah ESFAS TS were similar to those at Watts Bar prior to the Watts Bar revision in that several ESFAS "trip setpoint" values were bounded by "greater than" or "less than" symbols. Also, the Sequoyah TS Bases did not discuss nominal values. The inspectors then reviewed several TS required surveillance procedures to determine how the "trip setpoint" value was used by the licensee when calibrating ESFAS instruments. In each procedure reviewed, a nominal value of the TS "trip setpoint" value was used. This resulted in not setting appropriate instruments per actual TS "trip setpoint" requirements. All reviewed data was within the TS "allowable value" which is the TS condition for operability. Three of the surveillance procedures reviewed, which incorporate a nominal value, are listed below.

- 1-SI-ICC-030-042.4, CHANNNEL CALIBRATION OF CONTAINMENT PRESSURE CHANNEL IV RACK 12 LOOP P-30-42 (P-934), Revision 5.

- 1-SI-ICC-003-038.2, CHANNEL CALIBRATION OF STEAM GENERATOR 1 LEVEL CHANNEL II, RACK 5 LOOP L-3-38 (L-519), Revision 2.

- 2-SI-ICC-068-340.1, CHANNEL CALIBRATION OF PRESSURIZER PRESSURE CHANNEL I RACK 1 LOOP P-68-340 (P-455), Revision 3.

The licensee stated that they considered the TS ESFAS "trip setpoint" to be a nominal value. The licensee further stated that it was an industry practice among Westinghouse plants to calibrate ESFAS instrumentation within a plus or minus tolerance of the TS "trip setpoint" value, even though the "trip setpoint" values were bounded values. Sequoyah TS 3.3.2.1 states that the ESFAS instrumentation channels and interlocks shown in Table 3.3-3, Engineered Safety Feature Actuation System Instrumentation, shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3-4, Engineered Safety Feature Actuation System Instrumentation Trip Setpoints.

The inspectors determined the licensee failed to provide ESFAS instrumentation surveillance procedures which met the requirement of TS 3.3.2.1, Engineered Safety Feature Actuation System Instrumentation. This failure constitutes a violation of minor significance and is being treated as a non-cited violation, consistent with Section IV of the NRC Enforcement Policy. This item is identified as NCV 327, 328/95-26-03, Failure to Establish Adequate Surveillance Procedures for Safety-Related Equipment as Required by TS 6.8.1.

3.5.2 REVIEW OF RCS LEAK RATE DETERMINATION SURVEILLANCES

During this period, the inspectors reviewed three performance copies of 2-SI-OPS-068-137.0, REACTOR COOLANT SYSTEM WATER INVENTORY, Revision 5, and one performance copy of 1-SI-OPS-068-137.0, REACTOR COOLANT SYSTEM WATER INVENTORY, Revision 4. These SIs provide directions for performing water inventory balances on the RCS to determine total identified and unidentified leakage.

The inspectors reviewed the SIs, the test data, discussed the test results with the licensee; and determined the test results satisfied the surveillance requirements. The inspectors noted the licensee's calculated leak rates were below TS allowable limits; the licensee routinely investigated increases in calculated leakage; and that the licensee reperformed the SI if the results showed an increasing trend in leakage.

The inspectors independently verified the results of three of the reviewed SIs, by using NRC computer program RCS LK9, REACTOR COOLANT SYSTEM LEAK RATE DETERMINATION FOR PWRs. The results were in agreement for two of the three SIs. However, for the third SI, the NRC calculated total leakage and unidentified leakage was greater than the licensee's data by 0.07 gpm. See the table below for a summary of the results of this comparison. The inspectors noted that all calculated results (NRC and licensee) were within TS limits.

	LICENSEE CALCULATIONS	NRC RCS LK9 CALCULATIONS	TS LIMITS
IDENTIFIED LEAKAGE gpm	0.02	0.02	10
UNIDENTIFIED LEAKAGE gpm	0.03	0.10	1

The inspectors concluded that the licensee conducted the surveillances in a good manner, and appropriate investigations were conducted when an upward trend in leakage was observed.

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

4.0 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:

4.1 REVIEW OF SEQUOYAH 10 CFR 50.59 REQUIREMENT IMPLEMENTATION PROCESS

During the routine visit to the Sequoyah Nuclear Plant on December 6 - 8, 1995, the NRR Senior Project Manager for Sequoyah reviewed the procedures used by site personnel to perform safety assessments and safety evaluations in accordance with 10 CFR Part 50.59. Site Standard Practice SSP-12.13, 10 CFR 50.59 EVALUATIONS OF CHANGES, TESTS, AND EXPERIMENTS, Revision 5, dated October 6, 1995, consolidated the site-specific procedures used to perform the evaluations into the standardized guidance that is also being used at the Watts Bar and Browns Ferry Nuclear Plants. This effort was performed by a Safety Assessment/Safety Evaluation Redesign Team, which included representatives from each site. As a result, procedures used to evaluate design changes, TACFs, special tests, experiments, and procedure changes, reference this procedure for performance of safety assessments and safety evaluations, rather than containing instructions in each of the procedures.

The procedure changes were discussed with the licensee past and present "owners" of the procedures. Response to questions satisfied reviewer concerns, including the following that the licensee indicated would be evaluated:

- The Revision Description document lists the changes that were made to the 10 CFR 50.59 review procedures. Numbers 3, 4, 5, and 6 indicate that information that was removed is contained in an "administrative memo." The reviewer was concerned that this memo is not adequately identified by date, originator, or other designation, to differentiate it from any other administrative memo. Various personnel were, however, knowledgeable of the content of the memo and able to produce a copy.

- Appendix A, "Format and Content of Safety Assessments/Safety Evaluations and Criteria for Determining Whether an Unreviewed Safety Questions Is Created," states that "... the relevant sections of the Technical Specifications need to be reviewed against the proposed activity. The change, test, or experiment should be evaluated with respect to safety limits, limiting safety system settings, limiting conditions of operations, ... , and Technical Specification bases." The reviewer expressed the concern that this list does not indicate that the Technical Specification surveillance requirements should also be reviewed. The licensee indicated that these requirements would be addressed in the review process, even though not specifically stated in the instructions and would consider adding it to the next revision.

- Appendix A also contained a list of questions to be asked when reviewing the impact of the proposed change on the SAR. These questions do not address the need to include potential changes to surveillance requirements in the evaluation. The licensee indicated that these requirements would be addressed in the review process even though not specifically stated in the instructions and would consider adding it to the next revision.

  When questioned about removal of the Safety Assessment checklist from the evaluations performed for design changes, the licensee stated that the attributes of the checklist are contained in the design change evaluation procedure and, therefore, the checklist was not considered necessary. In addition, the preparer of the design change package could use the checklist if desired, and it would continue to be used for safety assessments that are performed for other purposes. The checklist is contained in SSP-12.13 as Appendix D, and consists of a list of 53 items (such as fire protection, pipe whip, toxic gases, single failure criteria, system design parameters, redundancy, diversity) that should be evaluated for their potential effect on nuclear safety as the change is being assessed.

Consolidation of the 10 CFR 50.59 process appeared to be an improvement in the process for performance of high-quality safety assessments and safety evaluations. Standardization of the process among the TVA plants and the team approach to design the process showed initiative.

Two design changes were reviewed for adequacy of their 10 CFR 50.59 assessment. They were chosen because the licensee's review determined that no safety evaluation was necessary because no unreviewed safety question, Technical Specification, or FSAR changes would result from the design change. DCN No. M11527A was written to reroute bypass lines that protect certain containment penetrations to eliminate low points in the lines which collect and concentrate particulate matter from process fluid. DCN No. M-11311-A was written to install new duct design for the removable duct section of the control rod drive mechanism non-safety related cooling duct work located in the Reactor Building. The analyses for both DCNs contained explanations that were clear and accurate. They appeared to be representative of high quality reviews that show the effectiveness of the safety analysis procedure.

The latest Updated FSAR dated May 12, 1995, that was submitted by the licensee summarizing the safety evaluations performed for the period of January 1, 1994 to November 16, 1994, was also reviewed. Questions raised by the reviewer were adequately addressed by the licensee. The quality of this document and the clarity of the explanations has significantly improved and was noteworthy.

4.2 REVIEW OF PCB 974 FAILURE

On December 21, 1995, at 6:27 a.m., Unit 2 was manually tripped by operators from approximately 100% power. The reactor trip was initiated when operators observed condenser pressure rising above the turbine trip setpoint due to loss of three condenser circulating water pumps. The condenser circulating water pumps tripped due to a fault condition in the 161 kV switchyard. The fault condition was caused by a failure of power circuit breaker (PCB 974), which caused a voltage drop in the 161 kV switchyard for approximately 5 cycles until the fault was cleared by other breakers opening.

On December 22, 1995, the inspector discussed possible failure modes of power circuit breaker 974 with the licensee, and accompanied TVA personnel to the 161 kV switchyard for an examination of power circuit breaker 974. No evidence of arcing was seen on the breaker contacts, support columns, or external bars. The licensee, at this time, also performed a visual inspection of phases A and B. No significant damage was identified on either phase.

Based on the ongoing root cause analysis meeting discussions and the field inspection of power circuit breaker 974, the inspector concluded that the licensee's response to this event was good. The inspector requested the that licensee provide the NRC a copy of the problem evaluation report which documents the root causes of the power circuit breaker failure upon completion of the investigation.

4.3 REVIEW OF FAILURES FOR UNIT 1 STEAM GENERATOR BLOWDOWN LINES

On December 29, 1995, the inspectors became aware of failures in the Unit 1 Steam Generator blowdown lines that were initially identified on December 28, 1995. Failures included:

- Crack in piping/weld on line upstream of 1 inch drain valve 1-1-912.

- Crack in piping on line upstream of pressure transmitter PT-15-55.

- Leak at downstream connection point for flow instrument transmitter FIT-15-43.

The inspectors met with licensee personnel on January 5, 1996, to discuss these failures. The licensee stated that failures on the 1 inch drain line had occurred twice within the last year. Corrective action for this location was to remove the drain valve and cap the line in accordance with a design change. Repairs were made to the other two failure locations prior to placing the system back in service. The inspectors noted that the failure locations were not in the safety-related portion of the steam generator blowdown system.

The inspectors questioned the licensee as to the cause of the failures. They were informed that the failures may have been caused by vibration of the blowdown system in this area when a relief valve lifted due to isolation of the river flowpath by a malfunction of a pressure control valve. PER SQ2340PER had been written on December 29, 1995, identifying the problem. A system evaluation of the condition, along with general discussion of corrective actions was completed and provided to Operations on December 30, 1995. However, the licensee had not finished the cause evaluation of the failures. The inspectors requested a copy of the interim evaluation as to why the system was satisfactory for operation at this time.

On January 9, 1996, the inspectors were provided a copy of the interim actions taken by the licensee to address corrective actions taken to allow the blowdown flowpath to the river to be placed back in service. These interim corrective actions included modification of the system to provide assurance that piping integrity would be maintained if the river flowpath was inadvertently isolated and repair of a loose air fitting on pressure control valve 1-PCV-15-44. The inspectors reviewed the interim evaluation and considered it addressed actions required prior to allowing the blowdown flowpath to the river to be placed back in service.

The inspectors concluded that the licensee had not documented a thorough evaluation of the failures experienced in the Unit 1 blowdown lines on December 28, 1995, and subsequent interim corrective actions for the system prior to returning the system to service. It therefore, was not clear to the inspector that the issue had been thoroughly evaluated.

Within the areas inspected, no violations were identified.

5.0 **PLANT SUPPORT** (64704,71750, 82301 and 92904)

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

5.1 PHYSICAL SECURITY - REVIEW OF SECURITY SYSTEM POWER FAILURE

On December 21, 1995, at 6:27 a.m., Unit 2 was manually tripped by operators from approximately 100% power. The reactor trip was initiated when operators observed condenser pressure rising above the turbine trip setpoint due to loss of three condenser circulating water pumps. The condenser circulating water pumps tripped due to a fault condition in the 161 kV switchyard. The fault condition was caused by a failure of PCB 974, which caused a voltage drop in the 161 kV switchyard for approximately 5 cycles until the fault was cleared by other breakers opening. As a result of the switchyard voltage drop, normal power to several plant security systems was lost. In addition, backup power for these systems also failed. Failure of both normal and backup power supplies portions of the plant security system required compensatory measures to be taken by the plant security organization. The compensatory measures were fully implemented as required by the security plan.

The inspector discussed the normal and backup power failures with the licensee and noted the following: Failure of power circuit breaker 974 resulted in a start signal to the security diesel generator which should have started and carried the security load per design requirements. The diesel generator started but failed to synchronize to the bus. Additionally, the uninterruptable power supply (UPS), which normally carries the security load during the 8 to 15 seconds that the diesel generator is accelerating to speed, failed to pick up the load and power was lost to the security loads.

On December 22, 1995, corrective actions completed by the licensee to restore the security electrical system to design requirements included (1) replacement of the voltage regulating transformer, (2) jumpering of an open cell in the UPS battery bank, and (3) performance of a load test which demonstrated the capability of the UPS battery to carry the security loads. Additional investigations were ongoing to determine the root causes of this event. The licensee was requested to provide the NRC a copy of the problem evaluation report upon completion of this investigation.

The inspectors concluded that the failure of both the emergency and battery backup portions of the relatively new system indicated additional management focus was necessary to address the issues and implement appropriate corrective actions.

Within the areas inspected, no violations were identified.

6.0 OTHER NRC PERSONNEL ON SITE

During the first two weeks of this period, (November 27 through December 8, 1995) an IPAP team inspection was conducted at the Sequoyah Nuclear Plant. The results of that inspection was discussed in Inspection Report 327, 328/95-25. Several issues in the IPAP report were referred to the resident inspectors for disposition. These issues are discussed in paragraphs 2 and 3 of this report.

7.0 EXIT

The inspection scope and findings were summarized on January 8, 1996, by William E. Holland with those individuals identified by an asterisk in paragraph 1. Interim exits were conducted on December 13, and 22, 1995. The inspector described the areas inspected and discussed in detail the inspection results. A listing of inspection findings is provided. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

TYPE	Item Number	Status	Description and Reference
VIO	327, 328/95-26-01	OPEN	Failure to follow procedures 0-SO-36-3, SSP-2.51, and 0-PI-OPS-000-606.0 (paragraphs 2.2.6 and 3.3).
VIO	327, 328/95-26-02	OPEN	Failure to follow the requirements of SSP-6.23 (paragraph 3.1).
NCV	327, 328/95-26-03	CLOSED	Failure to Establish Adequate Surveillance Procedures for Safety-Related Equipment as Required by TS 6.8.1 (paragraph 3.5.1).
IFI	327, 328/95-26-04	OPEN	Review Fuse and Breaker Coordination Evaluation Performed in Conjunction with PER SQ952204PER (paragraph 3.1).

8.0 ACRONYMS AND ABBREVIATIONS

ac	-	Alternating Current
ACR	-	Auxiliary Control Room
AFW	-	Auxiliary Feedwater
a.m.	-	Ante Meridiem
amp	-	Amperage
AOP	-	Abnormal Operating Procedure
ASOS	-	Assistant Shift Operations Supervisor

AUO	-	Assistant Unit Operator
BOP	-	Balance of Plant
CFR	-	Code of Federal Regulations
CRT	-	Cathode-ray Tube
dc	-	Direct Current
DCN	-	Design Change Notice
ERCW	-	Essential Raw Cooling Water
ESFAS	-	Engineered Safety Feature(s) Actuation System
°F	-	Degrees Fahrenheit
FRV	-	Feedwater Regulating Valve
FSAR	-	Final Safety Analysis Report
gpm	-	gallons per minute
I&C	-	Instrumentation and Control
IFI	-	Inspector Followup Item
IPAP	-	Integrated Performance Assessment Process
kV	-	Kilo-volts
MCC	-	Motor Control Center
MCR	-	Main Control Room
MDAFWP	-	Motor-Driven Auxiliary Feedwater Pump
MRC	-	Management Review Committee
MSR	-	Moisture Separator Reheater
MWT	-	Megawatts Thermal
NCV	-	Non-cited Violation
NOUE	-	Notice of Unusual Event
NRC	-	Nuclear Regulatory Committee
NRR	-	Nuclear Reactor Regulation
PCB	-	Power Circuit Breaker
PEDS	-	Plant Engineering Data System
PER	-	Problem Evaluation Report
p.m.	-	Post Meridiem
PMG	-	Permanent Magnet Generator
PORC	-	Plant Operations Review Committee
PZR	-	Pressurizer
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
SG	-	Steam Generator
SAR	-	Safety Analysis Report
SER	-	Safety Evaluation Report
SER	-	Sequential Event Recorder
SI	-	Surveillance Instruction
SOS	-	Shift Operations Supervisor
SSP	-	Site Standard Practice
TACF	-	Temporary Alteration Change Form
Tavg	-	Temperature-Average
TDAFWP	-	Turbine-Driven Auxiliary Feedwater Pump
TI	-	Temperature Indicator
TI	-	Temporary Instruction
TIIC	-	TVA Item Identification Code
Tref	-	Temperature-Reference
TS	-	Technical Specification
TVA	-	Tennessee Valley Authority
UO	-	Unit Operator

UPS	-	Uninterruptable Power supply
Vac	-	Voltage Alternating Current
Vdc	-	Voltage Direct Current
VIO	-	Violation
WO	-	Work Order
WR	-	Work Request