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

Report Nos.: 50-424/93-29 and 50-425/93-29

Licensee: Georgia Power Company
P. O. Box 1295
Birmingham, AL 35201

Docket Nos.: 50-424 and 50-425 License Nos.: NPF-68 and NPF-81

Facility Name: Vogtle 1 and 2

Inspection Conducted: December 19, 1993 - January 22, 1994

Inspector: D.A. Seymour for B. R. Bonser, Senior Resident Inspector — 2.15.94 Date Signed

D A S for R. D. Starkey, Resident Inspector — 2.15.94 Date Signed

D A S for P. A. Balmain, Resident Inspector — 2.15.94 Date Signed

Accompanied by: Deborah A. Seymour

Approved by: Paul H. Skinner — 2.15.94 Date Signed
P. Skinner, Chief
Reactor Projects Section 3B
Division of Reactor Projects

SUMMARY

Scope: This routine, inspection entailed inspection in the following areas: plant operations, surveillance, maintenance, Engineered Safety Feature System walkdown, cold weather preparation, and follow-up of open items.

Results: One Inspector Follow-up Item (IFI) was identified.

An uncontrolled dilution occurred on Unit 2 as a result of the unit reactor operator failing to maintain focus on an activity that changed core reactivity. The inspectors considered this a personnel error by the operator to self check and verify. An improvement has been noted in reducing the number of personnel errors and this event appears to be isolated (paragraph 2e).

During this inspection period two automatic reactor trips occurred on Unit 2. The first trip resulted from a fault in the Vogtle high voltage switchyard. The second trip was caused by several conditions which together resulted in a turbine trip/reactor trip.

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An IFI was opened related to the second trip to review instrument failures which contributed to the event and review other applications of this type instrumentation (paragraph 2f).

Cold weather preparations were reviewed. The inspectors found that a cold weather program has been implemented and appropriate actions are taken when cold weather is expected. During this inspection period unusually cold weather was experienced (paragraph 5).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*J. Beasley, General Manager Nuclear Plant
*W. Burmeister, Manager Engineering Support
*S. Chesnut, Manager Engineering Technical Support
*C. Christiansen, SAER Supervisor
R. Dorman, Manager Training and Emergency Preparedness
*G. Frederick, Manager Maintenance
W. Gabbard, Nuclear Specialist, Technical Support
*J. Gasser, Unit Superintendent
*M. Griffis, Manager Plant Modifications
*K. Holmes, Manager Operations
*D. Huyck, Nuclear Security Manager
W. Kitchens, Assistant General Manager Plant Support
R. LeGrand, Manager Health Physics and Chemistry
*W. Mundy, Senior Nuclear Specialist
*G. McCarley, ISEG Supervisor
*M. Seepe, Radwaste Supervisor
*M. Sheibani, Nuclear Safety and Compliance Supervisor
C. Stinespring, Manager Administration
*J. Swartzwelder, Manager Outage and Planning
C. Tynan, Procedures Supervisor
*T. Webb, Engineer Technical Support

Other licensee employees contacted included technicians, supervisors, engineers, operators, maintenance personnel, quality control inspectors, and office personnel.

Oglethorpe Power Company Representative

T. Mozingo

NRC Resident Inspectors

*B. Bonser
*D. Starkey
P. Balmain

*Attended exit meeting

An alphabetical list of abbreviations is located in the last paragraph of the inspection report.

2. Plant Operations - (71707)

a. General

The inspection staff reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, TSs, and administrative controls. Control logs, shift supervisors' logs, shift relief records, LCO status logs, night orders, standing orders, and clearance logs were routinely reviewed. Discussions were routinely conducted with plant operations, maintenance, chemistry, health physics, engineering support and technical support personnel. Daily plant status meetings were routinely attended.

Activities within the control room were monitored during shifts and shift changes. Actions observed were conducted as required by the licensee's procedures. The complement of licensed personnel on each shift met or exceeded the minimum required by TS. Direct observations were conducted of control room panels, instrumentation and recorder traces important to safety. Operating parameters were verified to be within TS limits. The inspectors also reviewed DCs to determine whether the licensee was appropriately documenting problems and implementing corrective actions.

Plant tours were taken during the reporting period on a routine basis. They included, but were not limited to the turbine building, the auxiliary building, electrical equipment rooms, cable spreading rooms, NSCW towers, DG buildings, AFW buildings, and the low voltage switchyard.

During plant tours, housekeeping, security, equipment status and radiation control practices were observed.

b. Unit 1 Summary

The unit began the period operating at 100% power and operated at full power throughout the inspection period.

c. Unit 2 Summary

The unit began the inspection period at 100% power. On January 7, 1994, the unit automatically tripped from 100% power due to a fault in the high-voltage switchyard. On January 8, the unit commenced a startup and reentered Mode 1. The unit reached 100% power on January 10. On January 19, the unit automatically tripped from 98.5% power due to a turbine trip on high MSR level caused by the tripping of HDP B (see paragraph 2.e). The unit entered Mode 2 later in the day on January 19 and entered Mode 1 on January 20. The unit reached 100% power on January 21 and operated there through the end of the inspection period.

d. Unit 2 Reactor Trip Due To Switchyard Fault

At 10:53 pm on January 7, 1994, Unit 2 automatically tripped from 100% power. The reactor trip was caused by a turbine trip. The turbine tripped on a main generator loss of load when both generator output breakers opened in the high voltage switchyard.

The initiating event was a fault on the Scherer shunt reactor located in the high voltage switchyard adjacent to the Vogtle Plant. The Scherer shunt reactor is a device that is located within the Vogtle high voltage substation that is used to control the capacitance of the 500 kV system. The Scherer 500 kV line is one of two 500 kV lines in the high voltage switchyard. The fault caused two air operated circuit breakers to open isolating the Scherer line. One of these breakers was one of the two generator output breakers. Operation of the two breakers to isolate the shunt reactor fault reduced control air pressure in the receivers at each breaker below a setpoint which actuated a backup protection scheme. This resulted in four additional breakers opening in the high voltage switchyard including the second generator output breaker.

All systems in the plant responded normally. During this event offsite power was not lost and all DGs were operable. Unit 2 was restarted on January 8 and returned to full power on January 10.

This event is discussed and reviewed in detail in NRC Inspection Report 424, 425/94-01.

e. Unit 2 Uncontrolled Dilution

On January 11, during a routine dilution on Unit 2, the reactor operator inadvertently set the total flow integrator incorrectly and diluted the RCS by about 715 gallons. The reactor operator intended to dilute 25 gallons but moved another digit while setting the total flow integrator allowing the dilution to continue. The flow rate of the reactor makeup water pump is about 100 gpm. The dilution continued for approximately seven minutes before the RO recognized the error. Boration and rod insertion were commenced to limit the power increase. Control bank D rods were inserted to 202 steps and power peaked at about 101.1%.

Makeup to the RCS is a routine evolution often performed several times a day. In this case the RO's attention was diverted from the task and a dilution that would have taken several seconds was allowed to continue for minutes. The inspectors concluded after reviewing this event that this was a personnel error by the RO. The procedures are clear and the RO knew the procedure and how it is performed. However, the RO failed to maintain focus on his primary responsibility of controlling core reactivity and ensuring the dilution stopped when expected.

The inspectors reviewed recent events and found no similar occurrences. However, the cause of this error was common to several past errors - a failure by personnel to self check and verify. As identified in previous reports, plant management continued to communicate their expectations in this area and adopted a program of self verification and checking. An improvement has been noted in the effort to reduce personnel errors and this event appears to be isolated. The licensee took prompt corrective action on this event by counseling the operator and briefing the CR staff on this event and management's expectations. This event is also being incorporated into operator training.

f. Unit 2 Automatic Reactor Trip Results From HDP Trip

On January 19, Unit 2 automatically tripped from 98.5% power due to a turbine trip on high moisture separator reheater level. Following the reactor trip all safety systems functioned normally. The licensee's investigation of the event determined that the event was initiated when the B HDP tripped. The licensee determined that the cause of the HDP trip was most likely a result of a steam leak on an instrument line connected to the B HDT low level switch. The leak apparently caused the switch to momentarily actuate and trip the HDP. A level transmitter that provides main control room indication is also on this instrument line. The HDT high and low level alarm switches are on a separate line and did not actuate prior to the HDP trip.

The licensee reviewed several other scenarios in addition to the steam leak which would have caused a low level condition in the B HDT and could not conclusively determine if the B HDT low level trip switch actuation caused the B HDP to trip. The licensee also investigated B HDP overcurrent relay settings since the HDP will also trip on an overcurrent condition. The results of the overcurrent relay setpoint investigation were also inconclusive.

The B HDT normally collects water which is drained from the 4B feedwater heater, the C and D MSRs, and the SGBD system. This water is then pumped by the B HDP from the B HDT to the feedwater system. When the B HDP tripped, actual level in the B HDT increased, backing up into the C and D MSRDTs and into the MSRs. The main turbine subsequently tripped when 2 out of 3 MSR high level switches actuated. The time from the B HDP trip, which initiated the transient, until the reactor trip was approximately two minutes and 20 seconds. During this time operators recognized the B HDP trip, and initiated a manual power reduction from 100% power.

In addition to the HDP trip, the licensee identified two other contributing causes to the reactor trip. The day prior to the event, the licensee removed B HDT High Level Dump Valve 2LV-4334 from service to repair seat leakage which was reducing plant efficiency. The valve would normally open upon sensing a high level in the B HDT following a HDP trip and prevent further level increase by discharging water to the main condenser. Maintenance on the valve was expected to be completed on January 19.

The MSRDT high level dump valves also did not function properly during the transient. Had these valves functioned properly condensate would not have backed up into the MSRs.

The licensee's investigation determined that MSRDT high level switches would have opened the valves if their sensing lines were not clogged with iron oxide buildup. The licensee also found that the controllers for the MSR dump valves were misadjusted and would not respond as desired. These two problem caused the failure of both means of opening the MSRDT high level dumps while at full power.

Based on the review of this event the inspector was concerned that the plugging of instrument sensing lines and misadjustment of valve controllers could potentially affect other applications. Since these issues contributed directly to a reactor trip and led to a challenge of Unit 2 safety systems this is identified as inspector follow up item IFI 424,425/93-29-01, Review Significance of Instrumentation Failures Contributing To Unit 2 Reactor Trip. The inspector will review the licensee's corrective actions to this event as part of the LER follow-up.

No violations or deviations were identified.

3. Surveillance Observation (61726)

a. General

Surveillance tests were reviewed by the inspectors to verify procedural and performance adequacy. The completed tests reviewed were examined for necessary test prerequisites, instructions, acceptance criteria, technical content, data collection, independent verification where required, handling of deficiencies noted, and review of completed work. The tests witnessed, in whole or in part, were inspected to determine that approved procedures were available, equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and systems restoration was completed.

SURVEILLANCE NO.	TITLE
14546-2	Turbine Driven Auxiliary Feedwater Pump Operability Test
14803-1	CCW Pumps and Discharge Check Valves Inservice Test

14980-1	1B-Diesel Generator Operability Test
14980-2	2B Diesel Generator Operability Test

The inspectors did not identify any problems or concerns during the observation of these surveillance activities.

b. Unit 1 Rod Control System Failure

On December 28, during performance of surveillance procedure 14410-1, Control Rod Operability Test, control bank A group 1 rods H6 and H10 indicated no movement on the DRPI when the rods were inserted. This procedure is a monthly surveillance that demonstrates the operability of the shutdown and control rods. The licensee immediately entered the LCO action statement for TS 3.1.3.1, Moveable Control Assemblies, and initiated troubleshooting.

The licensee quickly determined that the rod problem was electrical and in the rod group power cabinet. Diagnostic instruments found that the two rods were getting constant full current on the stationary gripper coils, preventing rod movement. During troubleshooting, however, the two rods were driven in to 220 steps and could not be withdrawn. This became a factor in resolving the rod movement problem since the two rods were below the bank A rod insertion limit and the six hour action statement for TS 3.1.3.6, Control Rod Insertion Limits, became applicable.

The licensee placed the two rods on the DC hold bus, replaced two circuit cards, and verified operability of the rods by repeating the surveillance test within the TS action time. The cards replaced were the group A phase control card and the firing circuit card. The suspect cards were returned to the vendor as part of the root cause analysis.

The inspector observed the licensee's actions throughout this event and was satisfied the actions taken were appropriate.

c. Review of IST Vibration Procedural Requirements

The inspector reviewed training, completed IST surveillances, and interviewed plant personnel to determine if IST vibration procedural requirements were met, and to determine the acceptability of using a hand-held pencil probe for obtaining vibration measurements with the IRD-820.

The IRD-820 Vibration Monitor is a microprocessor controlled, portable, battery operated vibration meter that has been used at Vogtle for several years. Two probes can be used with the 560 velocity pickup; a pencil probe or a magnetic base probe.

Training lesson plan EL-LP-07017-00, Revision 0, IRD-820 Vibration Meter, specified the use of the magnetic base "when possible," and also stated it "provides a more stable reading." The lesson plan included instructions on the correct use of the hand-held pencil probe. Job Performance Measure EL-JP-07013, IRD-820 Vibration Meter, stated that "The magnetic pickup should be used if possible. If the probe is used, it must be held perpendicular to the surface of the machine with just enough pressure to prevent chattering."

The inspector reviewed surveillance procedure 14801-1, NSCW Transfer Pump Inservice Test, performed on August 23, 1993 for Unit 1, Train A, and on August 17, 1993, for Unit 1, Train B. Procedure 14801-1 required the use of an IRD-820 Vibration Monitor with a 560 velocity pickup. The surveillance procedure did not specify which probe to use for taking measurements. The data sheets for completed surveillance procedures did not indicate which probe was used to acquire the vibration data. Discussions with several PEOs and electrical/maintenance workers who performed vibration measurements with the IRD-820 indicated that the choice of probe was usually left to the discretion of the individual taking the measurements. In some instances, a USS would request a specific probe be used, particularly if the reported measurements were inconsistent with previous results.

The inspector found that a wide variation in vibration results could be obtained if the magnetic base probe was incorrectly seated on the component being measured, or if the pencil probe was held incorrectly. Licensee personnel indicated that vibration measurements would be repeated when the results were significantly different than previously obtained reference values; and that the hand-held pencil probe would normally be used when the test surface was not large or flat enough to correctly place the magnetic probe.

The licensee's current IST vibration procedures state a preference for the CSI-2110 Vibration Monitor. The CSI monitor is a later model, is digital, is programmable, and allows for data trending. The magnetic probe for the CSI-2110 is smaller than the magnetic probe for the IRD-820. The licensee indicated that the CSI-2110 was easier to use and eliminated much of the variability exhibited by the IRD-820. Licensee procedures contain the option of using the IRD-820 Vibration Monitor. The resident inspectors have previously reviewed the use of the CSI-2120 Vibration Monitor (see IR 50-424,425/93-02).

The inspector also reviewed IST vibration trending data maintained by the IST engineer for the Unit 1 NSCW pumps and Unit 1 SI pumps from January 1990 to the present. The inspector did not identify any pump inoperability determinations due to vibration measurements during this time frame.

The inspector concluded that the use of the pencil probe to obtain vibration measurements was acceptable. The use of the pencil probe provided more reliable data than the magnetic base when measurements were taken on irregular or small surfaces where the magnetic base would not fit. The inspector did not identify any problems with vibration measurement procedures or with the vibration measurements reviewed.

No violations or deviations were identified.

4. Maintenance Observation (62703)

a. General

Maintenance activities were observed and/or reviewed during the reporting period to verify that work was conducted in accordance with approved procedures, TSs, and applicable industry codes and standards. Activities, procedures, and work orders were examined to verify proper authorization to begin work, provisions for fire, cleanliness, and exposure control, proper return of equipment to service, and that limiting conditions for operation were met.

The inspectors witnessed or reviewed the following maintenance activities:

MWO NOS.	WORK DESCRIPTION
29304135	Recalibrate Temperature Loop for DG HVAC System
19400056	Repair Unit 1 Annunciator System
19400235	RCP #2 Undervoltage Bistable "RCP Bus 2 Ch 2" Is Tripped
29304088	Remove and Inspect 4-way valve on MFIV 2HV5227

The inspectors did not identify any problems or concerns during the observation of these maintenance activities.

b. Review of Diesel Generator Maintenance Testing.

During this inspection period the inspector reviewed documentation of DG runs to determine if DG runs conducted for surveillance or post maintenance testing during Unit 1 refueling outage 1R4 were performed in accordance with procedures.

The inspector reviewed TS surveillance records for 24 hour DG ESFAS runs performed in March 1993. Diesel generator surveillance runs of 24 hours duration are required by TS 3/4.8.1.1, A.C.

Sources. The inspector reviewed completed procedures 14666-1 and 14667-1, Train A and Train B Diesel Generator and ESFAS Test, and verified that the 24 hour surveillance runs were completed per section 5.1 of the procedures. The inspector reviewed Table 1, DG 24 Hour Run, an hourly log completed during the surveillances, and verified that the DGs were operated at required loads for the full 24 hour duration of the surveillances.

The inspector reviewed documentation of end of cycle maintenance for the 1A and 1B DGs respectively in MWOs 19203304 and 19203305 for maintenance performed during the last Unit 1 refueling outage. The review included work completion sign off sheets for the maintenance procedures used during the maintenance activities. From discussions with system engineering personnel and review of MWO 19203305 the inspector determined that the 1B DG was shut down during a 35% load break-in run. MWO documentation stated that the engine was shutdown to repair an intake elbow air leak. The inspector reviewed copies of the Unit 1 DG start log for start numbers 1B-93-288 and 1B-93-289 and noted that the engine was maintained at 35% load for 40 minutes stopped for approximately two hours and then operated for 30 minutes at 35% load.

The inspector was initially concerned that stopping the 1B DG prior to completing the entire one hour run did not meet the intent of maintenance procedure requirements. Procedure 28708-C, Alternate EOC Diesel Checkout, step 4.46.5e requires that the DG be loaded from the control room at 35% load for one hour, however the procedure does not state that the DG must be continuously run at this load for one hour. The inspector verified, by reviewing the DG start logs, that the DG was loaded to 35% load for a total of one hour and ten minutes and determined that this met the requirements of procedure 28708-C.

Based on the sample of records reviewed the inspector concluded that surveillance and maintenance runs for the diesels were performed appropriately. One example was identified where the Unit 1B DG was shut down during a 1 hour maintenance run prior to completing the entire 1 hour. The inspectors review determined that the licensee's actions were acceptable and met the requirements of procedure 28708-C.

c. Review of Unit 1 Annunciator System Malfunction

On January 10, the licensee identified a problem with the Unit 1 annunciator system that affected the normal receipt and display of all annunciators in the Unit 1 control room. The malfunction was discovered when the annunciator ringback horn began to sound continuously. The ringback horn normally sounds only when a lit annunciator alarm condition clears and returns to normal. During initial troubleshooting of the ring back problem the licensee identified that the fast flash function of all the annunciators was also not working. Normally when an alarm is received the corresponding annunciator window illuminates with a fast flash and one of five different alarm horns sound for the panel where the annunciator window is located. The fast flash malfunction resulted in alarms being received with only the audible horn sounding and no visual fast flash display of the alarm windows. When the audible alarm was acknowledged at the control panels the incoming alarm window would illuminate with a solid display and the audible horn would silence which is the normal response.

The inspectors were concerned that the malfunctions in the annunciator system could have degraded the system's function to provide an assessment of plant conditions. The inspectors reviewed the licensee's compensatory actions taken in response to the problems, the troubleshooting and repair, and the response to NRC Information Notice 93-47, Unrecognized Loss of Control Room Annunciators.

The licensee initiated several compensatory actions to respond to the degraded condition including hourly walkdowns of the DG and TDAFW local panels and the initiation of special condition surveillance monitoring and logging significant plant parameters. Troubleshooting the annunciator system malfunction determined that a flasher/horn driver circuit card and an annunciator alarm logic circuit card had failed and caused the fast flash and ringback problems. Several additional annunciator circuit cards had also failed and resulted in isolated problems with individual alarm windows. The inspector verified by observing several alarms being received in the Unit 1 control room that the loss of the fast flash function slightly delayed the identification of an alarm. The alarms would illuminate with a solid display when the horns were acknowledged. The inspector verified by reviewing control room logs that hourly walkdowns of the DG and TDAFW local panels were performed. The inspector also observed that Data sheets 1, 3, 5, 6 and 7 of procedure 14915-1, Special Condition Surveillance Logs were initiated.

The inspector observed portions of the maintenance activities and testing of the annunciator system performed under MWO 19400056. Troubleshooting isolated the fast flash problem to logic chassis 3 in the annunciator cabinets. There are a total of 68 logic chassis in the annunciator system which contain up to 24 alarm logic cards that monitor the status of a plant parameter and provide actuation of horns and alarm windows. Each logic chassis also contains one flasher/horn driver to provide drive capability for audible horns and routing of flash and push button signals. All flash signals are generated in one miscellaneous logic chassis by a master flasher circuit card which is connected to the flasher/horn driver cards in each logic chassis.

During the maintenance activities in logic chassis 3, the inspector observed that the licensee stationed a licensed operator in the TDAFW pump room and operators in the control room performed additional monitoring of AFW and MFP indications. This maintenance disabled alarms for these systems. The licensee also replaced other failed circuit cards in the annunciator system before returning the annunciator system to service.

The inspector reviewed the licensee's response to NRC IN 93-47 and found the licensees actions addressed the concerns identified in the IN.

Based on this review the inspector determined that the annunciator malfunction did not render the annunciator system inoperable. The inspector noted that the licensee's compensatory actions for the degraded condition and the work performance in troubleshooting and repair of the malfunction was good.

No violations or deviations were identified.

5. Cold Weather Preparations (71714)

The objective of this inspection was to determine whether the licensee has effectively implemented a program to protect safety-related systems against extreme cold weather. To evaluate the licensee's program, the inspector walked down portions of safety-related systems which can be affected by extreme cold weather, verified that procedures were in place to inspect, calibrate, and test heat tracing and freeze protection equipment and verified that those procedures had been recently performed. The inspector also reviewed all open MWOs associated with heat tracing and discussed the freeze protection program with personnel from maintenance, operations, work planning, and engineering support.

The inspector observed that, in general, the physical condition of heat tracing and freeze protection was good. The inspector verified that operators routinely perform procedure 11877-1/2, Cold Weather Checklist, when the outside air temperature is less than or equal to 32 °F. and that WRTs are initiated when deficiencies are noted. Procedure 11901-1/2, Heat Tracing System Alignment, is performed by Operations at the required frequency. Maintenance personnel also perform surveillances on the solid state heat tracing control system and freeze protection panels at required intervals. During this inspection period the outside air temperature was less than 20 °F on several occasions and no significant freezing problems were observed. The inspector noted that during the inspection period the number of open MWOs related to freeze protection varied from 25 to 29. While that number seemed large, a review of those MWOs determined that none appeared to affect the operability of safety-related systems.

The inspector concluded that the licensee has adequately implemented a cold weather preparation program and appropriate actions are taken when extreme cold weather is expected. The inspector also concluded, after discussions with supervisory personnel in operations, maintenance, work planning and engineering support, that there is not a central point of coordination which has the responsibility of ensuring that freeze protection deficiencies and compensatory actions are reviewed and acted upon prior to the onset of extreme cold weather.

No violations or deviations were identified.

6. ESF System Walkdown (71710)

The inspectors completed a walkdown of the Unit 2 Auxiliary Feedwater System trains A, B, and C. The review included the two condensate storage tanks, the two motor driven AFW pumps, the turbine driven AFW pump, the steam supply to the turbine driven pump, and the three AFW pumps discharge to main feedwater. The inspectors reviewed the Technical Specifications, FSAR, procedures, and the system drawings to verify the correct system lineup and correct electrical breaker positions. The examination identified no significant problems. Several minor discrepancies were identified and given to the licensee for correction. The inspectors also identified a number of examples were the valve description in the lineup procedure differed from the description on the valve tag. Room locations of some of the valves in the system lineup procedure were also incorrect. The walkdown did not identify any problems that would effect the operability of the system.

No violations or deviations were identified.

7. Follow-up (90712) (92700) (92702)

The Licensee Event Reports and violation listed below were reviewed to determine if the information provided met NRC requirements. The determination included: adequacy of description, verification of TS compliance and regulatory requirements, corrective action taken, existence of potential generic problems, reporting requirements satisfied, and relative safety significance of each event.

a. (Closed) VIO 424/93-07-05, Failure To Take Adequate Corrective Action Results In Loss Of Decay Heat Removal, and LER 50-424/93-03, Loss Of Residual Heat Removal Due To Inadvertent Closure Of Residual Heat Removal Inlet Valve.

The licensee responded to the violation in correspondence dated June 16, 1993. The violation involved a loss of decay heat removal due to an inadequate review by I&C personnel performing maintenance on circuitry which affected an RHR pump suction valve. The I&C personnel involved were counseled regarding the importance of reviews before performing work. Other I&C personnel were briefed on the causes of this incident and the need for reviews and work controls. Also NAS circuit cards were specifically covered.

Replacement of NAS cards can cause momentary actuation of their end devices and appropriate precautions are necessary to protect equipment. The inspector verified that I&C personnel received this training. The licensee also enhanced their risk assessment and work controls during the recent Unit 2 refueling outage to limit this type of work during periods of increased risk. This event occurred during a period of higher risk when only one train of decay heat removal was operable.

Based on this review of the licensee's corrective actions the violation and the LER are closed.

b. (Closed) LER 50-425/93-003, Room Temperature Readings Not Performed - Missed Technical Specification Surveillance.

This event was caused by the premature use of a revision to Procedure 14001-2, Shift Area Temperature Log, prior to the completion of a design change and the appropriate change to TS. Personnel responsible for revising the procedure failed to perform an adequate review prior to revising the procedure and have been appropriately disciplined. Temperature readings were promptly taken for the three rooms involved and were found to be satisfactory. Procedure 14001-2 was revised to include the three rooms which had been deleted.

Based on a review of the licensee's corrective actions, this item is closed.

c. (Closed) LER 50-425/93-002, Containment Personnel Airlock Found Inoperable When Interlock Found Defeated.

This event was caused by personnel error when the Unit 2 containment personnel airlock interlock was not restored prior to exiting mode 5. The individual responsible for leaving the interlock defeated was counseled regarding the importance of self-checking. Other maintenance personnel who perform airlock interlock activities were briefed on the significance of the event and the importance of ensuring that such work activities are properly completed. Procedure 25236-C, Airlock Maintenance, was revised to include a note to use Procedure 25237-C, Containment Personnel Airlock Doors, if the airlock interlocks need to be disabled or enabled.

Based on a review of the licensee's corrective actions, this item is closed.

No violations or deviations were identified.

8. Exit Meeting

The inspection scope and findings were summarized on January 24, 1994, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection findings. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during the inspection.

8. Abbreviations

AFW	-	Auxiliary Feedwater System
CFR	-	Code of Federal Regulations
CR	-	Control Room
DC	-	Deficiency Card
DG	-	Diesel Generator
EOC	-	End of Cycle
ESF	-	Engineered Safety Feature
ESFAS	-	Engineered Safety Features Actuation System
°F	-	Degrees Fahrenheit
FSAR	-	Final Safety Analysis Report
HDP	-	Heater Drain Pump
HDT	-	Heater Drain Tank
HVAC	-	Heating, Ventilating and Air Conditioning
I&C	-	Instrumentation and Controls
IFI	-	Inspector Followup Item
IN	-	NRC Information Notice
IR	-	Inspection Report
ISEG	-	Independent Safety Engineering Group
IST	-	Inservice Test
kV	-	Kilovolt
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
MFP	-	Main Feed Pump
MFIV	-	Main Feedwater Isolation Valve
MSR	-	Moisture Separator Reheater
MSRDT	-	Moisture Separator Reheater Drain Tank
MWO	-	Maintenance Work Order
NAS	-	A type of circuit card
NPF	-	Nuclear Power Facility
NRC	-	Nuclear Regulatory Commission
NSCW	-	Nuclear Service Cooling Water System
PEO	-	Plant Equipment Operator
RCS	-	Reactor Coolant System
RCP	-	Reactor Coolant Pump
RHR	-	Residual Heat Removal System
RO	-	Reactor Operator
SAER	-	Safety Audit And Engineering Review
SGBD	-	Steam Generator Blowdown
SNC	-	Southern Nuclear Company
SRO	-	Senior Reactor Operator
SSPS	-	Solid State Protection System
TDAFW	-	Turbine Driven Auxiliary Feedwater
TS	-	Technical Specifications
UOP	-	Unit Operating Procedure
USS	-	Unit Shift Supervisor
VIO	-	Violation
WRT	-	Work Request Tag
1R4	-	Unit 1 Fourth Refueling Outage