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

Report Nos.: 50-424/92-02 and 50-425/92-02

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: January 26 - February 22, 1992

Inspectors:	PA Skinner for	3/20/92
	B. R. Bonser, Senior Resident Inspector	Date Signed
	PA Skinner for	3/20/92
	R. D. Starkey, Resident Inspector	Date Signed
	PA Skinner for	3/20/92
	P. A. Balmain, Resident Inspector	Date Signed
Approved By:	Alan R Herdt	3/20/92
	for P. Skinner, Chief Reactor Projects Section 3B Division Reactor Projects	Date Signed

SUMMARY

Scope: This routine inspection entailed inspection in the following areas: plant operations, surveillance, maintenance, ESF system walkdown, review of licensee events reports and followup.

Results: One apparent violation was identified for failure to follow procedure. I&C technicians, after determining that the as found settings on an Over Pressure/Delta Temperature runback bistable were outside the allowable limits, adjusted the bistable setpoints without performing the applicable calibration section of the procedure as required. Upon realizing that the appropriate calibration data sheet was not completed the technicians willfully falsified the data sheet.

An ESF walkdown of the Unit 2 Piping Penetration Filtration and Exhaust system was performed. Based on the walkdown no concerns regarding operability of the system were identified. Several minor discrepancies were noted and brought to the attention of the licensee for corrective action.

Two similar DG failures have occurred in the past year. The licensee's investigations into these failures has been unable to determine a root cause. On February 5, 1992, when DG 2B was paralleled to the grid as part of its normal monthly surveillance test, VARS decreased to -4200 and the DG voltage controller would not respond. This failure was similar to failures which occurred on DGs 2A and 2B on January 29, 1991.

General housekeeping in the penetration rooms has improved, but the material condition of sampling system valves continues to be poor. Work orders are not consistently generated on these leaking valves to initiate the repair process and alert the corrosion assessment engineers of a potential problem.

DETAILS

1. Persons Contacted

Licensee Employees

*B. Baker, Maintenance Engineer
*H. Beacher, Senior Plant Engineer
*J Beasley, Assistant General Manager Plant Operations
*R. Brown, Supervisor Operations Training
W. Burmeister, Manager Engineering Support
*S. Chesnut, Manager Engineering Technical Support
*C. Christiansen, Safety Audit and Engineering Group Supervisor
W. Copeland, Supervisor - Materials
C. Coursey, Maintenance Superintendent
*J. D'Amico, Outage Scheduling Supervisor
R. Dorman, Manager Training and Emergency Preparedness
*J. Gasser, Operations Unit Superintendent
M. Hobbs, I&C Superintendent
K. Holmes, Manager Health Physics and Chemistry
*D. Huyck, Nuclear Security Manager
W. Kitchens, Assistant General Manager Plant Support
*R. LeGrand, Manager Operations
*G. McCarley, ISEG Supervisor
R. Mansfield, Plant Engineer Supervisor
*R. Odom, Plant Engineer Supervisor
A. Parton, Chemistry Superintendent
*B. Raley, Plant Engineer Supervisor - Maintenance
*M. Seepe, Radwaste Supervisor
*M. Sheibani, Nuclear Safety and Compliance Supervisor
*W. Shipman, General Manager Nuclear Plant
*C. Stinespring, Manager Administration
J. Swartzwelder, Manager Outage and Planning
C. Tynan, Nuclear Procedures Supervisor
L. Ward, Manager Maintenance - Acting

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 Interview

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, Technical Specifications, and administrative controls. Control logs, shift supervisor logs, shift relief records, LCO status logs, night orders, standing orders, and clearance logs were routinely reviewed. Discussions were conducted with plant operations, maintenance, chemistry and 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 observed to verify they were within TS limits. The inspectors also reviewed [illegible]s 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 and the low voltage switchyard.

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

      The inspectors verified that the licensee's health physics policies/procedures were followed. This included observation of HP practices and review of area surveys, radiation work permits, postings, and instrument calibration.

      The inspectors verified that the security organization was properly manned and security personnel were capable of performing their assigned functions; persons and packages were checked prior to entry into the PA; vehicles were properly authorized, searched, and escorted with the PA; persons within the PA displayed photo identification badges; and personnel in vital areas were authorized. Also during this inspection period the inspectors observed security force weapons training and qualification.

b. Unit 1 Summary

Unit 1 remained at full power throughout the reporting period.

c. Unit 2 Summary

The unit began the inspection period operating at 100% power. With Unit 2 approaching the end-of-cycle, unit coastdown began on February 16. At the end of the inspection period power had decreased to 94%. The second Unit 2 refueling outage is scheduled to begin on March 13.

d. Emergency Drill

On January 31, 1992, the licensee conducted a repeat of the semi-annual HP drill which had been conducted on December 9, 1991. The drill in December had failed to meet several of the drill objectives and was judged by both the licensee and the inspectors to be unsatisfactory. The January drill was conducted using a scenario similar to the previous drill. The drill objectives were to complete all onsite and offsite notifications, to timely activate all onsite ERFs, to respond to simulated elevated radiation measurements in the environment, to perform onsite personnel accountability, to respond to intruders, and to properly respond to a medical emergency.

During the repeat drill, the inspectors observed the drill from the TSC, OSC, and the scene of the medical emergency. The inspectors took particular note as to whether the deficiencies observed in the previous drill had been corrected. In each case, the previous deficiency was corrected. Overall, the drill went smoothly and was judged by the licensee and the inspectors to be satisfactory and met the drill objectives. Several minor findings were noted by the licensee during the drill critique and have been assigned to the appropriate group for corrective action.

e. Failure of Diesel Generator 2B To Load

On February 5, DG 2B was started for its monthly surveillance run per procedure 14980-2, Diesel Generator Operability Test. The DG was synchronized and then paralleled to the 4160 KV emergency bus per the procedure. When the DG output breaker was closed, the Low Excitation alarm was received and the VARS decreased to approximately -4200 while the DG load was 1500 KW. The Control Room operator attempted to increase the VARS by depressing the "raise" push button on the voltage controller but the voltage controller would not respond. After consulting with the DG system engineer, the output breaker was opened, the DG was synchronized to the grid again and the output breaker was reclosed. The voltage responded correctly, the DG was loaded and the surveillance was successfully completed. The licensee entered the applicable LCO Action statement at the time of the failure and exited the LCO upon the successful completion of procedure 14980-2.

The licensee assigned an event critique team to review the failure and to identify the root cause. On February 6 and 7, the 2B DG was run again with monitoring equipment connected to capture the response of the voltage regulator during the test. The tests conducted on these two days did not obtain any information which could identify the cause of the abnormality that occurred on February 5. The licensee is now testing the 2B DG weekly for its normal surveillance with monitoring equipment connected. The licensee developed a Temporary Engineering Procedure, T-ENG-92-01, which was conducted on February 25. The purpose of this procedure was to simulate as closely as possible the conditions present during the 2B DG failure on February 5. Particular attention was paid to determining the low excitation limiter setpoint and any abnormalities at that setpoint. The test determined that the excitation limiter setpoint is -2400 KVARS. The excitation limiter is functional only after the generator output breaker is closed and is affected only by external operation of the voltage controller pushbutton in the control room. An internal voltage regulator problem was therefore apparently responsible for the -4200 KVAR reading on February 5 and could have caused the KVAR reading to go below the setpoint of the exitation limiter. The February 25 test could not reproduce the previous problem and the critique team could not confirm definitely whether the problem was in the parallel circuitry, the voltage regulator, or some other wiring problem. Neither can the licensee confirm that the 2B D/G would have been capable of performing its safety function either in the unit or parallel mode of operation on February 5.

When the inspection period ended, the licensee event critique team had not completed its review of the 2B DG failure. The licensee will replace the voltage regulator and followup with the D/G vendor on any other actions which can be taken. The inspectors will continue to monitor the investigation of this DG failure. It should be noted that a similar failure occurred on the 2A D/G on January 29, 1991 and is discussed in IR 50-424, 425/91-02. The licensee was unable to definitively characterize the cause of that failure.

f. Boric Acid Buildup On Sampling Valves

The inspectors performed a walkdown of the Unit 1 and Unit 2 piping penetration rooms. Excessive accumulation of boric acid was observed on two safety-related containment isolation valves. Both valves are part of the RCS sampling system. One valve was located in each unit. A concern regarding significant boric acid leakage and accumulation in these rooms was raised and documented during the Maintenance Team Inspection (IR 50-424,425/91-03). It was noted during the MTI that no attempt was made to contain the leakage. Leakage noted during this inspection was effectively contained to the immediate vicinity of the leaking valves and general housekeeping in the penetration rooms had improved.

Following the walkdown, the inspectors reviewed the licensee's actions taken to control the leakage and to evaluate any boric acid induced corrosion. The inspectors learned that the licensee normally cleans and decontaminates components located in high radiation areas approximately every two months. A work request is normally initiated to repair the leaking components and engineering technical support is notified to perform a corrosion assessment if needed.

In response to the inspectors concern, the licensee decontaminated the valves and performed a corrosion assessment of the borated valves noted in the walkdown. Following the decontamination, the licensee determined that three valves were leaking, not two as discussed earlier. The two leaking valves on Unit 2 had work orders written to repair the leaks (2HV3502, RCS Hot Leg 1 and 3 Sample Valve, and 2HV3508, Pressurizer Liquid Sample Valve), the Unit 1 valve (1HV3502, RCS Hot Leg 1 and 3 Sample Valve) did not have a work order written to repair the leak. The licensee initiated a work request to repair this valve. Also the licensee's corrosion assessment determined that a support plate associated with 1HV3502 had significant material degradation. The licensee determined that the degradation was not severe enough to affect the operability of the support and initiated a Deficiency Card to track the problem. A work order was also generated to repair the support and to possibly apply a protective coating to the support.

The inspector concluded that general housekeeping in the penetration rooms has improved, but the material condition of sampling system valves continues to be poor. The inspectors also concluded that work orders are not consistently generated on these leaking valves to initiate the repair process and alert the corrosion assessment engineers of a potential problem.

g. 2A Diesel Generator Jacket Water Leak

On February 19, during observation of a routine surveillance of the 2A DG, the inspector noted excessive leakage of jacket water which required manual makeup to the DG jacket water standpipe. Following this observation, the inspector expressed an operability concern to the licensee for long term operation of the DG under LOSP conditions. Under LOSP conditions, demineralized water makeup would not be available via the demin water transfer pumps, since these pumps are not provided with emergency power.

The licensee evaluated the concern and prepared a Standing Order (2-92-02) to provide a primary and backup means of providing makeup to the DG jacket water standpipe in the event that power is lost to the demin water transfer pumps. The primary means of makeup is with gravity fill from the denim water storage tank through the normal makeup valve. If the demin storage tank level is less than 14 feet gravity fill would not provide adequate makeup. A back-up filling method was developed using the firewater supply. Fire water can be pumped to the standpipe under LOSP conditions since the system is supplied with diesel driven pumps. Instructions for connecting the fire water supply to the DG jacket water standpipe are provided in the Standing Order. Tools and appropriate connections are located in the Control Room and are designated for emergency use only.

h. Control of Divergent Axial Flux Oscillation

During this inspection period the Unit 2 reactor core began to experience a divergent axial flux oscillation. Flux oscillations of this nature occur predominantly at the end of cycle. Fuel burnup in the core throughout the cycle causes flux to shift towards the top of the core at end of cycle due to the burnup of the bottom and center portions of the core. At end of cycle this redistribution leads to conditions which can initiate a divergent flux oscillation due to the decreased axial stability of the core. The inspectors noted that reactor engineering and operations efforts to analyze and implement appropriate actions to bring the oscillation under control were effective. Reactor Engineering projected the behavior of the oscillation and advised operators of the approximate time to damp the oscillation. Throughout the coastdown, the inspectors observed that the licensee closely monitored the core's behavior and updated target AFD values as necessary to reflect core burnup. Operation's and Reactor Engineering's efforts in maintaining control of AFD are noteworthy.

No violations or deviations were identified.

3. ESF Walkdown (71710)

The inspectors conducted a walkdown of the Unit 2 Piping Penetration Filtration and Exhaust system. Procedure 11305-2, Auxiliary Building System Alignment, and system drawings were used to verify proper system alignment. All electrical and mechanical components were found in their required position. The inspector noted several labeling discrepancies between the line up procedures and the component labels. Minor format errors were identified in the line-up procedures. These items were brought to the attention of the licensee. Based on this walkdown the inspectors had no concerns with the operability of the system.

In response to minor procedural inefficiencies, inconsistencies and component tagging deficiencies found by the licensee and the frequent finding of similar deficiencies by NRC inspectors, the licensee is undertaking a comprehensive walkdown program on both units. All Operations shifts have been assigned systems to walkdown and document discrepancies for action. This is a long-term program which will take several months to complete. Once this effort is completed it is expected that procedures will be enhanced and more operator oriented. They will be consistent between units, and procedures and component tags will agree.

This program is also an effort to increase the sense of accountability and system ownership among the Operations shifts.

No violations or deviations were identified.

4. Surveillance Observation (61726)

a. 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.

Listed below are surveillances which were either reviewed or witnessed:

Surveillance No.	Title
14514-C	Fuel Handling Building Post Accident Exhaust System Operability Test
14545-2	Motor Driven Auxiliary Feedwater Pump Monthly Operability Test
14807-2	Motor Driven Auxiliary Feedwater Pump Inservice Test
14804-2	Train A Safety Injection Pump Inservice Test
14980-2	Diesel Generator Operability Test
24811-2	Delta T/T AVG Loop 2 Protection Channel II Analog Channel Operational
54067-C	Fuel Handling Building Post Accident Ventilation System Actuation
54824-2	Train A CCW Pumps Response Time Test

b. Failure To Follow Surveillance Procedure

On January 28, 1992, at 1:54 a.m., I&C technicians were authorized to perform the ACOT section of Unit 1 surveillance procedure 24812-1, Delta T/T Avg Loop 3 Protection Channel III 1T-431 Analog Channel Operational Test (ACOT) and Channel Calibration. The purpose of this procedure is to verify operability and settings in reactor trip system instrumentation for Overtemperature Delta T and Overpower Delta T, and ESFAS instrumentation Low RCS T Avg Coincident With a Reactor Trip. The procedure consists of disabling the process sensors from the field instrument and artificially inserting a test signal into the circuitry to verify the settings in the actuation circuitry are correct. Should the as found settings be found outside the allowable range, the allowable settings are given in a data sheet contained in the procedure, the procedure requires that an adjustment be accomplished by performing a calibration. When the calibration is complete the procedure requires a repeat of the ACOT. At 4:01 a.m., the procedure was signed off as being performed satisfactorily.

Following the recently completed outage on Unit 1 the licensee implemented design changes to revise the runback setpoints on OTDT and OPDT from 3% below the reactor trip setpoint to 1% below the reactor trip setpoint to eliminate runback alarms (see IR 424, 425/91-32). As part of the design change several procedures were revised. During the revision process, through an oversight, the ACOT section of procedure 24812-1 was not revised to reflect the new 1% margin. The calibration section of the procedure was revised correctly.

At 4:11 a.m., on January 28 the OP Delta T Runback bistable momentarily alarmed on the Main Control Board. The licensee became concerned after the OPDT bistable had alarmed twice. Based on the modifications described above, there was apparently no reason for a runback bistable to alarm. I&C supervision immediately began a review of the ACOT procedure to see if any discrepancies existed. Upon reviewing the procedure, it became apparent that the ACOT procedure was incorrect and the numbers written in the calibration data sheet were not valid data readings since they corresponded to a 1% margin setting and not the 3% margin in the ACOT.

Due to these problems there was some suspicion by the licensee management of procedure non-compliance and falsification of the data sheet. The inspectors held discussions with licensee personnel, including upper level management, to verify the events. When the two I&C technicians who performed the procedure were confronted with these discrepancies they immediately admitted that they had made the adjustment without following the procedure and had created the data in the calibration data sheet to cover their failure to follow the procedure. The technicians stated that when they had performed the procedure the as found tolerances in the verification section of the ACOT procedure did not match the expected tolerances listed in the attached data sheet. When the technicians found this condition they called their supervisor, as required, and asked for direction. The supervisor told them to call for QC and complete the procedure. The apparent meaning of the supervisor and the reason to call for QC was to adjust the bistable setpoints by performing the calibration portion of the procedure and to have QC verify the adjustment. As mentioned above, the only acceptable method of adjusting bistable setpoints is to perform the calibration procedure. At this time there was some discussion between the two technicians as to the proper method to restore the bistable to within tolerance. Rather than following the procedure and using the calibration section for the bistable, the decision was made to make an adjustment to the bistable using the ACOT configuration even though this method was not procedurally correct. After making the adjustment QC was called to witness that the as left readings were within acceptable limits. The QC inspector verified that the I&C technicians obtained acceptable ACOT readings and signed off the QC hold point in the calibration section of the procedure.

After completing their work, one of the technicians returned to the I&C shop to review the paperwork. At this time he realized that for the paperwork to be complete a calibration data sheet was required since an adjustment had been made. To support the adjustment made, the technician filled out the calibration data sheet with numbers that he thought would appear correct. The technician did not realize, however, that the ACOT portion of the procedure was incorrect and the voltage readings in the calibration section would not correspond to the voltage readings in the ACOT section.

The technicians were also questioned by the licensee about any possible previous incidents of this type while working at Vogtle. The licensee stated that they assured their supervision they had never engaged in this type of non-compliance and falsification previously. The licensee also stated a review of past work performed by the I&C technicians was conducted, which resulted in no similar occurrences. The licensee was not aware of any other similar events.

The licensee has discussed the significance of this event with the supervisor as well as the procedure writer. The need for clear, proper communication was emphasized with the supervisor, and the importance of the incorporation of new data into procedures was stressed with the procedure writer. Although the QC inspector verified the ACOT data in accordance with the procedure hold point, a closer review and verification of the work activity by QC may have detected the discrepancies.

The licensee identified this event and notified the resident inspectors as soon as it became apparent that the data sheets had been falsified. The licensee has performed a thorough investigation and has taken disciplinary action against the individuals involved. The licensee also stated that the disciplinary action would be an appropriate deterrent.

The inspectors also reviewed the safety significance of incorrectly setting the runback bistable. The runback functions on both OTDT and OPDT are not assumed or required for accident mitigation in the accident analyses presented in the FSAR. The receipt of runbacks could, however, prevent the unit from achieving 100% power. The receipt of signals from two bistables would have caused a turbine runback. In this case the bistable was set in a conservative direction which would have caused a runback to occur at a lower power. This event is identified as an apparent Violation 50-424/92-02-01: Failure To Follow Procedure Results in Turbine Runback Alarm and Falsification of Data. This apparent violation will be the subject of further NRC review.

One apparent violation was identified.

5. Maintenance Observation (62703)

a. General

The inspectors observed maintenance activities, interviewed personnel, and reviewed records to verify that work was conducted in accordance with approved procedures, TSs, and applicable industry codes and standards. The inspectors also frequently verified that redundant components were operable, administrative controls were followed, clearances were adequate, personnel were qualified, correct replacement parts were used, radiological controls were proper, fire protection was adequate, adequate post-maintenance testing was performed, and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service.

Outstanding work requests were reviewed to ensure that the licensee gave priority to safety-related maintenance activities.

The inspectors witnessed or reviewed the following maintenance activities:

MWO No.	Work Description
19104850	1T-12624C Piping Pen Filter 2 Temp indicator appears to have a bad indicator light
19105751	Install Crankcase Heaters In DG 1A Air Compressor-2
19200061	Replace Cells 6 And 24 In Battery 1AD1B
19200230	Troubleshoot Failure Of Unit Available Light On DG 1A Control Panel
19200365	Cell 25 In Battery 1AD1B Was Measured At 2.14V On February 17. Place Cell On Single Cell Charger At 2GO VDC For 4 Days.
29200464	Install monitoring instrumentation on 2A DG

29200567	NSCW Cooling Tower A pump 1 failed to start

b. Containment Penetration Local Leak Rate Test Failures

Since January 1, 1992, there have been three Unit 2 containment penetration local leak rate test failures out of a total of nine tests performed. These failures occurred on check valves in penetrations 12A, Chemical Injection; 23, breathing air; and 80, Service Air. The three piping penetrations vary in diameter from 1/2 inch to 4 inches. The containment isolation valves are either Rockwell or Dresser lift check valves or Dresser, or Anchor Darling swing check valves. The inspector discussed these failures with the cognizant maintenance engineer to determine if there was a common mode of failure. Following the discussion and review of historical leakage data, the inspector concluded that there was no single dominant failure mode for these valves and that the failures were unrelated.

On February 13, maintenance entered containment to inspect and repair, if necessary, check valve 2-1204-U4-034 in the Service Air System penetration 80. When the valve was disassembled it was found to be closed but a manufacturer's casting mark was discovered on one side of the valve hinge which prevented the valve from opening to a full open position. Even though the valve had the potential to stick open, the cause of the excessive leakage was determined to be pitting on the valve seating surface. The licensee removed the casting mark and refurbished the seating surface. The valve then passed its local leak rate test. The licensee had discussed this valve failure with the manufacturer, Anchor Darling, and a Part 21 report was being considered as this inspection report period ended.

A similar failure occurred on August 29, 1991, on check valve 1-1204-U4-034 on Unit 1 and is discussed in LER 424/91-15. In that instance, casting marks were again discovered but in that case they caused the valve to stick fully open. One of the corrective actions stated in that LER was to inspect the corresponding Unit 2 valve during the Unit 2 refueling outage in the Spring of 1992.

c. Battery Chargers Out Of Service For Extended Period

During this inspection period the inspectors noted that two safety-related battery chargers 1AD1CD and 2CD1CA had been considered inoperable for an extended period of time. The inspectors were concerned and verified that the licensee was taking appropriate actions to restore this equipment.

The DC electrical systems are designed to provide a reliable source of continuous power for control, instrumentation and DC motors. Four safety-related DC battery banks are installed per unit; each battery bank has two redundant battery chargers both of which are normally in service. TS 3.8.2, DC Sources-Operating, requires that the four battery banks and one charger associated with each battery be operable per unit.

The inspector noted that the licensee initiated Information LCOs to track the inoperable battery chargers in November 1991. Charger 1AD1CB was considered inoperable due to oscillations following its associated battery load test. Charger 2CD1CA was removed from service due to load sharing problems.

The inspector reviewed these problems with the system engineer. Historically, the majority of battery charger problems have been associated with internal control circuitry. Oscillations on the chargers have occurred under two conditions; 1) with a battery disconnected from its distribution system (the battery breaker open), and 2) under heavy load conditions following battery discharge surveillances. In addition to oscillation problems the chargers have also experienced load sharing problems. The licensee has initiated design changes (MDDs 91-V1M103, 91-V1M105, and 91-V2M104) to modify the control circuit boards to prevent these oscillations. In conjunction with the modifications, as a preventive measure, the licensee is refurbishing circuit boards by replacing components which are subject to aging. The licensee is performing this upgrade generically throughout the plant on both safety-related and non safety-related chargers.

The delay in returning battery chargers 1AD1CB and 2CD1CA to service can be attributed to delays from the vendor in supplying the large volume of refurbished control boards required for the charger upgrades. Based on this review, the inspector was satisfied with the licensee's actions in returning the battery chargers to service.

No violations or deviations were identified.

6. Review of Licensee Reports, Followup (90712) (92700) (92701) (92702)

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

a. (Closed) VIO 50-424/91-31-02, "Failure To Maintain Boron Injection Flow Path."

   (Closed) LER 50-424/91-010, "Personnel Error Leads To Inadequate Surveillance."

The USS and RO were counseled regarding the importance of adequate review of information when completing TS surveillances requirements. An adequate review of the LCO status log would have revealed a LCO on one of the boration flowpaths and a reference to a clearance which called for the two manual valves to be shut. The appropriate boron injec flowpath procedures, 14405-1/2 and 14406-1/2, were revised on January 15, 1992 to include normally "locked open" manual valves. Step 5.3a of these procedures now informs the operator that the position of these manual valves may be verified by checking the "Safety Related Locked Valve Manipulation Log," procedure 11888-C.

b. (Closed) LER 50-424/91-011, "Auxiliary Feedwater Actuation While Preparing For Test."

The Steam Generator Water Level Control Operator was counseled regarding the importance of attention to duty and the need to maintain control over work activities in his area. The AFW Pump and Check Valve Cold Shutdown Inservice Test procedures were revised on December 19, 1991, to state that steam generator levels should be maintained between 50% and 75% narrow range during performance of the tests. The DCP Implementation and closure procedure was revised on January 22, 1992, to more effectively control the timing revisions necessitated by design changes. The specific change that addresses timely revisions to plant procedures is the Return to Service Checklist. The new process requires that each department sign in the Mod Log for completion of their procedure revisions. At any time after the field work is complete, the shift superintendent can determine what procedures have to be revised, which department is responsible, and which of the revisions have been completed.

c. (Closed) LER 50-424/91-014, "Fuel Handling Building Isolation From Radiation Monitor Signal."

The cause of the event was a loss of power to the Fuel Handling Building radiation monitors ARE-2532A and ARE-3532B which caused them to fail to the "safe" condition, resulting in a FHB isolation. The root cause of the loss of power could not be determined. Following troubleshooting and testing, the radiation monitor were returned to service.

d. (Closed) VIO 50-424,425/91-15-04, "Inadequate Pressurizer Pressure Calibration Procedures."

(Closed) LER 50-424/91-005, "Improper Pressurizer Pressure Transmitter Calibration."

All eight pressurizer pressure transmitters were recalibrated. A Waiver of Compliance was requested by GPC and granted by NRC Region II to allow sufficient time to complete the transmitter recalibrations. The Waiver of Compliance allowed an additional 18 hours to be applied to the 6 hour TS 3.0.3 requirement for the units to be in

Mode 3 (Hot Standby). The recalibration for both units was completed in 11 hours and 30 minutes which was within the 24 hours allowed under the waiver. Additionally, the 8 calibration procedures for the pressurizer pressure transmitter were revised to include the static head corrected factor.

The licensee conducted a broadness review of level, pressure and flow transmitters to verify that static head correction factors have been included as appropriate. This review included Reactor Protection system instruments, Engineered Safety Features instruments, and some balance of plant instruments that are important to safety or performance (approximately 456 instruments for Unit 1 and 2 combined). Of these 456 instruments, 218 had no elevation difference between the tap and transmitter, and 172 had an elevation difference with the required head correction applied. The remaining 66 instruments (including the 8 head pressurizer pressure instruments) had an elevation difference, but a head correction was not applied. Each of these was reviewed and it was determined that, with the exception of the pressurizer pressure channels, there were no cases where a head correction was necessary for TS operability considerations. However, as a result of this review, a further evaluation of these instruments was made to determine if any corrections should be applied to enhance system performance. Calibration procedure revisions for the above instruments were completed prior to the next calibration of the effected instruments. The licensee also performed a programmatic review of the procedure writer's guide and made enhancements concerning static head corrections.

e. (Closed) IFI 50-424,425/91-28-02, "Review Licensee Root Cause Evaluation Of System Leaks."

The licensee's root cause evaluation for numerous water spills during outage evolutions during refueling outage 1R3 concluded that the spills occurred due to inefficient work practices, poor organization and accessibility of clearance information, and inadequate procedural controls for release of valves within a clearance for functional tests.

The majority of spills which occurred during 1R3 were attributed to valves which were released from a clearance as a functional test. A functional test is intended to allow testing of equipment after it has been repaired. In the past there had been some misunderstanding on the meaning of functional test. The functional test form was misleading and the time allowed for a functional test had been excessive. The licensee is strengthening procedural controls governing the release of equipment. Procedure 00304-C, Equipment Clearance and Tagging is being revised to change the term functional test to functional release. The functional release form will be revised to clearly distinguish the release sequence from the restoration sequence. In addition, the time frame for which a component can be functionally released is shortened from four days to two days. Under the revised procedure the clearance will be rehung on components after the two days has expired.

During the upcoming outage on Unit 2 the licensee will track clearances by system which is expected to provide operators with a more useful and accurate means of determining system status. The inspectors will review the effectiveness of these clearance and tagging program enhancements during 2R2 which begins next inspection period.

f. (Closed) IFI 50-424/91-31-03, "Followup Of Concerns Associated With AFW Actuation."

Following a review of this event (LER 50-424/91-011), the inspector had three areas of concern which warranted further review. These areas included operator awareness; a failure in the design change process to implement a work order to calibrate the affected control loops to incorporate new setpoints; and the design change package and Return to Service checklist containing no verification to determine the status of plant procedures associated with the DCP.

This incident was particularly striking because it exemplified the three problem areas given above. After a more complete review of this event, it is apparent that the direct cause of this event was an error by the operator. There were, however, other factors which led to the personnel error. These included procedure 14748-1, AFW Pump And Check Valve Cold Shutdown Inservice Test, not specifically stating the water levels to be maintained in the SGs; a valve stroke time test delaying the SGWLC operator from reinitiating feedwater flow to SGs 1 and 4 in a timely manner; and a failure to recalibrate the DG low level alarm setpoint to 44% following a design change. The inspector concluded that the licensee's proposed corrective actions in this area were appropriate.

This incident also called into question the return to service process following completion of a design change. The Design Change Package and the Return to Service checklist did not appear to contain a verification of the actual status of required procedural changes or the implementation of those changes. As a result there was no mechanism to determine the status of the DCP in the affected plant procedures. As a result of this incident and other events caused by a lack of knowledge of design change package status, the licensee has revised the requirements for implementation and closure of DCPs.

A change to the Modifications Log maintained in the Control Room will aid operators in ensuring awareness of DCPs in progress. Formerly, a narrative summary of DCPs planned, regardless of status, was placed in the Modifications Log. The log now will only contain the Return

To Service checklists and a narrative summaries for those DCPs in progress.

The responsible engineer, as before, will sign the RTS checklist signifying that a walkdown and review of the implementing MWOs indicates that the DCP is complete, the functional testing is complete, the actual ABNs are complete and component labeling is complete. After the responsible engineer has completed the RTS checklist, the engineer will now notify impacted departments to sign the RTS checklist acknowledging that changes are complete or scheduled for completion and the modification is acceptable for return to service. Previously when the engineer had completed a walkdown and notified impacted departments of a pending RTS it was left to the discretion of the Unit Shift Supervisor to place the system back in operation.

The inspectors will evaluate the implementation of these changes during the upcoming Unit 2 refueling outage.

No violations or deviations were identified.

8. Exit Meeting

The inspection scope and findings were summarized on February 24, 1992, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection findings listed below. 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 this inspection.

Item No.	Description and Reference
APPARENT VIOLATION 424/92-02-01	Failure To Follow Procedure Results in Turbine Runback Alarm and Falsification of Data

9. Abbreviations

ABN	As Built Notice
ACOT	Analog Channel Operational Test
AFD	Axial Flux Difference
AFW	Auxiliary Feedwater System
CCW	Component Cooling Water Systems
DC	Deficiency Card
DCP	Design Change Package
DCR	Design Change Request
DG	Diesel Generator
ERF	Emergency Response Facility
ESF	Engineering Safety Features

GPC	Georgia Power Company
HP	Health Physics
I&C	Instrumentation and Control
IFI	Inspector Followup Item
ISEG	Independent Safety Engineering Group
KW	Kilowatt
LCO	Limiting Conditions for Operations
LER	Licensee Event Reports
LOSP	Loss of Off-Site Power
MTI	Maintenance Team Inspection
MWO	Maintenance Work Order
NPF	Nuclear Power Facility
NRC	Nuclear Regulatory Commission
NSCW	Nuclear Service Cooling Water
OPDT	Over Pressure Delta Temperature
OSC	Operations Support Center
OTDT	Over Temperature Delta Temperature
PA	Protected Area
QC	Quality Control
RCS	Reactor Coolant System
Rev	Revision
RO	Reactor Operator
RTS	Return to Service
SG	Steam Generator
SGWLC	Steam Generator Water Level Control
TS	Technical Specification
TSC	Technical Support Center
USS	Unit Shift Supervisor
VAR	Volt-Amp-Reactive
VIO	Violation