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

Report Nos.: 50-424/92-07 and 50-425/92-07

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: March 22, 1992 - April 25, 1992

Inspector: for W. H. Miller Jr. 5-20-92
B. R. Bonser, Senior Resident Inspector Date Signed

for W. H. Miller Jr. 5-20-92
R. D. Starkey, Resident Inspector Date Signed

for W. H. Miller Jr. 5-20-92
P. A. Balmain, Resident Inspector Date Signed

Approved by: P. A. Skinner 5/21/92
P. Skinner, Chief Date Signed
Reactor Projects Section 3B
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SUMMARY

Scope: This routine, inspection entailed inspection in the following areas: plant operations, surveillance, maintenance, refueling activities, modifications and followup on previous inspection findings.

Results: Two non-cited violations were identified:

One non-cited violation involved a failure to demonstrate the operability of a containment isolation valve prior to returning it to service after maintenance. Prior to performing maintenance on a Unit 1 hot leg sample valve the USS did not enter the appropriate TS LCO. As a result actions were not taken to maintain TS compliance while the valve was considered inoperable (paragraph 2.e).

The second non-cited violation involved an inadequate calibration procedure used for setting the open permissive interlocks on the RHR system RCS loop suction valves. The procedure allowed setting the opening interlocks above the TS limit. This resulted in one valve being set to a value too high (paragraph 3.d).

Two IFIs were identified:

One IFI involves fully evaluating the safety significance of the DG 2B sequencer timing failure and the licensee's corrective actions following identification of the sequencer design deficiency (paragraph 3.b).

The second IFI involves followup on the licensee's evaluation of previous ECCS flow balancing data and their revision of applicable testing procedures (paragraph 3.c).

Operator response to several Unit 1 transients which occurred during this inspection period due to equipment failures was prompt and effective in preventing further plant complications (paragraph 2.b).

The licensee resolved a longstanding problem with the DG voltage regulation system which had resulted in under excitation when the DGs were paralleled to a bus powered from its normal supply. This problem only occurred when the DG was paralleled at a voltage below that of the energized bus. The licensee's persistent efforts to resolve this problem are considered a strength and have resulted in enhancing their understanding of the operation of the DG excitation system (paragraph 6).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*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
. Coursey, Maintenance Superintendent
*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
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
*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 supervisors' 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 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. The inspectors also made tours of the Unit 2 containment building. On one of the containment tours the inspector accompanied the licensee on a personnel safety walkdown of containment. Several items were noted for correction, mostly in the area of unsafe electrical cords, scaffolding, and safety lights.

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 within the PA; persons within the PA displayed photo identification badges; and personnel in vital areas were authorized.

b. Unit 1 Summary

The unit began the period operating at 100% power. On April 2, power was reduced to 60% power to remove the B main feedwater pump from service due to the failure of its discharge check valve. Power was increased to approximately 75% on April 3. On April 5 a power reduction to less than 65% power commenced in order to isolate the sixth stage feedwater heaters to search for missing check valve parts. On April 8, main turbine control valve number four failed shut and power dropped to 50%. The control valve was repaired and power restored on April 8. Also on April 8, a power supply for several control room instruments including a pressurizer level channel failed which caused a loss of letdown flow. Letdown was subsequently restored in accordance with the appropriate Abnormal Operating Procedure. The plant returned to full power on April 11, and the unit remained at that level through the end of the inspection period.

c. Unit 2 Summary

The unit began the period in Mode 6 with core off-load in progress. Core off-load was completed on March 23. The unit remained defueled until April 4, when core alterations commenced and the unit entered Mode 6. Fuel reload was completed and verified on April 7. The reactor vessel head was set on April 11 and the unit entered Mode 5 on April 13. On April 15, RCS fill and vent was completed. On April 24, the unit entered Mode 4 and was in this status at the end of the inspection period.

d. Unit 1 Main Feed Pump "B" Discharge Check Valve Failure

On April 2, with Unit 1 operating at 100% power, control room operators received high vibration alarms for both main feedwater pumps. They then noticed that the discharge pressure of the "B" MFP had increased to approximately 1450 psi from a normal pressure of approximately 1100 psi. The rpm of both MFPs had also increased from a normal 5200 rpm to approximately 6100 rpm. After reviewing P&IDs and discussing with shift supervision the possible reason for such a feedwater pump response, it was determined that the failure of the "B" MFP discharge check valve was the most probable cause and that it had probably become lodged in the discharge piping of the pump thus causing the high pump discharge pressure. Approximately 30 minutes after the initiation of this event, with the unit in a stable condition at 100% power, operators began a power reduction to 60% so that the "B" MFP could be stopped and isolated to investigate the problem. During the event there was a slight steam flow/feedwater flow mismatch. Operators took manual control of the main feedwater regulating valves to stabilize the steam flow/feed flow mismatch.

When power had been reduced to 60 percent, the "B" MFP was stopped and the pump discharge MOV was closed. The subsequent investigation revealed that the discharge check valve had failed. The intact valve disc assembly was located approximately 30 line feet downstream, lodged in the pipe elbow immediately upstream of the feed pump discharge MOV. On April 4, the disc was successfully removed from the feedwater line. It should be noted that a previous failure of the pump discharge check valve was caused by a poor hinge pin design which allowed the pins to work out of the disc resulting in disc/hanger separation. That design was later changed to prevent the hinges pins from becoming loose and dislodged. This particular failure on April 2 was attributed to the disc and hanger assembly becoming separated from the valve body and not with a problem associated with the hinge pins.

The licensee then began a search for the two capscrews and the capscrew locking plate device which had become separated from the disc and hanger assembly. The two capscrews are used to bolt the disc and hanger assembly to the valve body. The two capscrews and the locking plate were subsequently found in the 6A and 6B feedwater heaters. The 6A and 6B heaters are the high pressure feedwater heaters located downstream of the MFPs. One of the bolts was broken into two parts as was the locking plate device. The licensee then began an investigation into the cause of the failure. They discovered that the check valve body is drilled and tapped to accept three one inch capscrews. Further, both the locking device and hanger shims are also drilled to fit over an assembly consisting of three capscrews. However, the disc and hanger assembly of the failed valve contained only two holes. The hangers supplied by the vendor, Pacific Valve, as stock spares are blanks which do not contain any holes for capscrews. At the time of replacement the hole locations must be transferred from the valve body and then drilled by the licensee. According to the vendor this is to ensure that the field setup of the check valve is correctly completed and that factory machining does not introduce misalignments in the disc and seat. The vendor also confirmed that the recommended installation of the disc and hinge assembly required the use of three bolts, not two. The licensee subsequently inspected the remaining three feedwater pump discharge check valves, two on Unit 2 and one on Unit 1, and discovered that only the 1A MFP discharge check valve had the required three bolts installed. The licensee has since added a third bolt to each valve to meet vendor requirements.

During a review of procedure 26465-C, Pacific Pressure Seal Check Valve Maintenance, the licensee discovered that there was no guidance on torquing the hanger capscrew nor on the importance of using the locking plate device. These procedural deficiencies have been corrected. In conclusion, this check valve event was apparently due to the failure of the locking device which permitted the improperly torqued capscrews to back out and eventually free the disc and hanger assembly. Contributing to this failure was the absence of a third capscrew. The licensee is conducting a broadness review to determine what other applications there might be at Vogtle for this type check valve.

e. Failure to Test Containment Isolation Valve

On April 13, 1992, with Unit 1 in mode 1, maintenance technicians obtained approval from the USS to perform a MWO on RCS hot leg sample valve, 1HV-3502. This valve is also a containment isolation valve. The maintenance technicians proceeded to replace a packing gland nut in order to stop a packing leak. On April 15, a different USS was reviewing this work order and discovered that no stroke time testing had been performed following the packing nut installation. TS 4.6.3.1, Containment Isolation Valves Surveillance Requirements, requires that a CIV shall be demonstrated operable prior to its return to service after maintenance by performance of a cycling test, and verification of cycling time. The USS immediately initiated stroke time testing which demonstrated that the valve would close within the required time limits.

The cause of this event was a failure on the part of the USS who initially approved the MWO to recognize the need for entering the LCO action at the time of the packing nut installation. Had the USS recognized this it would have ensured completion of the appropriate action while the valve was considered inoperable. As a result of this error the licensee failed to comply with the TS action statement between April 13 and April 15. During this time period there were no plant events which required the CIVs to isolate.

This event is a violation of TS 3.6.3, Containment Isolation Valves. This violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B. of the Enforcement Policy. This is identified as NCV 424/92-07-01: Failure to Test Containment Isolation Valve Leads to TS Violation. This event and the licensee's corrective action are also described in LER 424/92-01.

f. Emergency Drills

On March 25, 1992, the licensee conducted a table top exercise in the Vogtle EOF. Participants in the drill included key licensee representativ state, county, and local representatives from Georgi South Carolina; and the Vogtle resident inspectors. The exercise consisted of walking through an actual drill scenario and each of the participants describing their actions as if this were an actual event. The drill was beneficial in that it provided the participants the opportunity to meet and talk with their counterparts and provided a chance to gain a better understandin and get assistance in several important areas. These areas included: Actions different local and state officials would be taking at different Emergency Action Levels; problems with understanding the Emergency Notification form; generation of news releases and media contacts; different communications that would take place during an event; and details of making Protective Action Recommendations when there is an off-site release.

On April 22, 1992, the licensee conducted a practice exercise. This exercise was a limited participation drill due to the on-going refueling outage. The purpose of the drill was to demonstrate accident assessment and classification, notification, activation of emergency response facilities, radiological assessment and control, and the coordination of public information. Overall the drill was satisfactory in meeting the drill objectives.

One non-cited violation was 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.

Listed below are surveillances which were either reviewed or witnessed:

Surveillance No.	Title
24732-1	SMA-3 Seismic Trigger Control AXSH-19922 ACOT
14667-2	Train B Diesel Generator and ESFAS Test
26859-C	Static Testing of Motor Operated Valves Using MOVATS 3000 Analysis & Test System-2LV-0112C
14701-1	Reactor Trip Breaker UV and Shunt Trip Test
54054-2	Control Room Emergency Ventilation System Performance Test (section 5.3)
24726-1	Time History Accelerograph & SMA-3 Recorder 1AXT-19905 Analog Channel Operational Test And Channel Calibration
54084-C	DMIMS Data Analysis & Comparison (Unit 1)

b. 2B Sequencer Timing Failure

On April 9, the licensee identified during review of data obtained during B train ESFAS testing, that the sequencer experienced an unexpected 14.3 second pause between load sequence steps 4 and 6 during the safety injection portion of the surveillance. This surveillance was being performed under procedure 14667-2, Train B Diesel Generator and ESFAS Test. This procedure is used in part to verify the surveillance requirements of TS 4.8.1.1.2.h.12 which require that the automatic load sequencer timer is operable with the interval between each load block within 10% of its design interval, and the surveillance requirements of TS 4.3.2.2 which require the ESF response time of each ESFAS function to be within the limits for the time interval from safety injection initiation to ESF component breaker closure.

The sequencers are designed to sequence required ESF loads onto the 4160V ESF buses in intervals of approximately 5 seconds. The 14.3 second delay experienced during the ESFAS test resulted in the failure to operate within the required interval. The licensee subsequently initiated troubleshooting to determine the cause of the failure and generated an information LCO on the 2B sequencer.

The licensee performed troubleshooting under MWO 29201332 and temporary engineering procedure T-ENG 92-06, which were used to instrument the sequencer, simulate an SI and to collect step time data for the nine load sequence steps. The licensee performed the test four times. During the second test, the sequencer experienced the same timing failure that occurred initially. Based on data collected during these tests and the repeat failure, the licensee and the vendor concluded that the problem was most likely due to a logic fault in the controller 'A' module, which is the main sequencer actuation logic circuit card.

The licensee replaced the controller 'A' module card and performed functional testing consisting of several manual test panel tests and a temporary engineering procedure. This engineering procedure (T-ENG 92-07), was used to simulate a UV, an SI, and a UV concurrent with SI actuation; record step time data; and to verify sequencer operability.

Following the functional testing the vendor reviewed the test data and determined that the circuit card replacement did not solve the timing problem. Additional test monitoring points were added and the licensee performed testing at various ATI steps. The ATI is a continuous diagnostic testing device which inputs signals to much of the sequencer actuation logic in order to verify proper logic operation. The ATI completes a testing cycle once every 120 seconds. The licensee observed that the timing failure occurred when the SI test was initiated during ATI steps 61 and 72. ATI steps 61 and 72 test the operation of timers which are used in the portion of the sequencer which monitors for degraded bus voltage.

The timers tested at steps 61 and 72 are the 20 second timer and 0.8 second timer respectively, which are used in the sequencer's logic to actuate the UV sequence if bus voltage degrades to 90% for 20 seconds or 71.5% for 0.8 seconds. The timing failure occurred when an SI signal was generated during the 20 second timer test. The SI sequence was initiated, which automatically defeated the ATI, during the valid SI sequence the 20 second timer finished counting and generated a UV actuation test pulse that reset the sequencer's main timing bus and caused the valid SI sequence to reset and start over. The reset resulted in the observed pause. This failure mechanism occurred for 20 seconds every 120 seconds or one sixth of the time. ATI step 72 caused an identical condition, however, for only a 0.8 second duration.

Following identification of the cause and nature of the sequencer timing failure, the licensee concluded that all four of the sequencers were subject to this failure and may not properly sequence required loads on a valid ESF actuation. The licensee subsequently declared the Unit 1 A and B sequencers inoperable and entered TS 3.0.3, since this unit was in a mode which requires the sequencer actuation logic for both units to be operable. The licensee then installed a temporary modification which disabled the ATI function to prevent it from interrupting the timing sequence, functionally tested the sequencers and declared them operable. The Unit 2 sequencers were also modified to defeat the ATI. With the ATI disabled, the licensee will periodically test the sequencer logic until a design change to restore the ATI is implemented.

The inspector considers the licensee's exhaustive steps to fully investigate the 2B sequencer timing failure and to subsequently test the function of the sequencer's logic following an actuation logic card replacement a strength. Data obtained from these efforts allowed the licensee and vendor to identify the root cause of the timing failure. However, at the close of the inspection period, the inspector had not fully evaluated the safety significance of the timing failure. The inspector will review the significance of the failure; the adequacy of the temporary modifications made in the sequencer panels to restore operability; performance of interim testing; and the licensee's review of previous sequencer deficiencies which could potentially be attributed to this issue. These concerns are identified as IFI 50-424,425/92-07-02, Review and Followup of Significance of DG 2B Sequencer Timing Failure.

The inspector will also review the licensee's safety evaluation of the effect of this failure on the plant's design basis and any relationship to the sequencer surveillance testing issues and performance review discussed in IR 424,425/91-05, 424,425/91-28, and 424,425/91-33.

c. ECCS Flow Balancing Criteria

During a Westinghouse review for potential excessive pump runout of the CCPs and SIPs during post LOCA recirculation (see IR 91-28) in October/November 1991 an inconsistency was noted in Unit 1 procedure 14721-1, ECCS Subsystem Flow Balance and Check Valve Refueling Inservice Test, relative to allowances provided for unlocking and adjusting the ECCS injection branch line throttle valves.

Up to the current Unit 2 refueling outage, procedures 14721-1 and 14721-2 were written such that the plant could unlock and adjust the CCP branch line throttle valves, with the criteria that the sum of the three lowest branch line flows be set at a value greater than or equal to 284 gpm. A criteria was also provided which ensured relative balancing between the four branch lines. These criteria are consistent with Vogtle TS 4.5.2.h, however, according to Westinghouse, it does not ensure an ECCS setup consistent with the existing accident analysis. A similar situation also exists for the SIP system.

The original system conditions were established during Vogtle preoperational testing. The preoperational procedures apparently identified the acceptance criteria for establishing flowrates consistent with the ECCS accident analyses. Compliance with the accident analyses was ensured by establishing, in addition to meeting the present TS flowrate requirements, a flowrate of 470 gpm in all four CCP cold leg injection lines with the difference between any two branch lines being less than 10 gpm. Similarly, a 620 gpm flowrate was required in the SIP cold leg injection lines.

The current Westinghouse ECCS flow analysis assumes that the net system resistance and pump performance curves each fall within allowable ranges. The TS CCP flow rate (284 gpm - three lowest branch lines) was based on the weakest allowable pump curve and the highest allowable system resistance. These assumptions were used to establish minimum delivered flowrate during a large break LOCA.

Westinghouse found that the current Vogtle ECCS subsystem flow balance inservice test procedure allows total system resistance to be increased beyond the ranges assumed in the Westinghouse ECCS flow analysis. In the extreme case the procedure would permit the valves in the CCP system to be throttled to limit pump runout flow to approximately 459 gpm (284 gpm total down the three lowest injection lines plus approximately 95 gpm down the remaining branch line plus 80 gpm seal injection). The original procedures used during pre-op testing required pump runout to be set at approximately 550 gpm. The difference in throttling is significant and according to Westinghouse calculations represents a 175 percent increase above the maximum allowable range for total resistance.

Although the VEGP TS will ensure that a sufficient ECCS flow rate is delivered to the core in the case of a large break LOCA they do not guarantee adequate system performance for all other break sizes. The reason for this is that the TS are not adequate for re-establishing total system resistance. In other words the branch line throttle valves can be set too low with the current TS flowrate requirements, since the 470 gpm flowrate for the CCP injection lines and the 620 gpm flowrate for the SIP cold leg injection lines are not included in TS.

Westinghouse reviewed the assumptions in the ECCS analysis and provided the licensee with recommendations for future adjustments to ECCS branch line throttle valves. The recommendations will be incorporated into plant procedures.

In view of this information the inspector was concerned that the licensee may have set ECCS branch line flows too low in the past and operated in an unanalyzed condition. Also the TS do not include values which are important in setting branch line flows. Following completion of the Unit 2 ECCS flow balancing test during the current outage, the licensee requested Westinghouse to evaluate the test results. Westinghouse reviewed the test results for both the CCP cold leg flow balancing test and the SIP cold leg and hot leg flow balancing tests and found them acceptable. In their review of other data, the licensee found that Unit 1 CCP injection line flow had been set at 460 gpm during the last outage. The licensee is having this reviewed for acceptability. The licensee is also reviewing ECCS flow balancing data from past outages. A preliminary review of this data indicates past flow balancing was acceptable and there is no current or past safety issue. The licensee is also planning to submit a proposed TS amendment to include more definitive requirements for flow balancing.

Pending completion of the licensee's review of Unit 1 and past ECCS flow balancing data, and revision of applicable procedures this issue is identified as IFI 424,425/ 92-07-03 Evaluation of ECCS Flow Balancing Data and Test Procedure Revisions.

d. Inadequate Calibration Procedure for RHR System Open Permissive interlocks.

On March 25, the licensee identified a procedure inadequacy which allowed calibration of the RHR system suction isolation valves open permissive interlock bistable to a value greater than that allowed by the TS surveillance requirement of 377 psig. The purpose of the RHR suction isolation valve open permissive interlock is to prevent challenging the RHR suction relief valves setpoint (450 psig) when considering instrument error and margin. The RHR interlocks are addressed in TS 4.5.2.d.1a, ECCS Surveillance Requirements. The TSs require verification of RHR suction valve interlock operability by demonstrating that the interlocks prevent the valves from being opened when a simulated or actual RCS pressure signal is greater than or equal to 377 psig.

The deficiency was identified by a procedure writer while performing revisions to calibration procedures in conjunction with a design change to delete the RHR autoclosure interlock (see paragraph 5b). Procedures to calibrate the open permissive interlock were originally intended to set the bistable at 365 psig to prevent challenges to the RHR suction relief valves but were found in error. The error existed for both units and allowed the open permissive interlocks to be calibrated from a range of 365 psig to 387 psig which exceeds the 377 psig TS limit. This applied to RHR suction isolation valves 1HV-8701A&B, 1HV-8702A&B, 2HV-8701A&B and 2HV-8702 A&B.

A review of calibration records showed that the Unit 1 OPI bistables were calibrated within the TS limit. Review of Unit 2 calibration records showed the OPI bistable for

2HV-8702 was calibrated in February 1989 to a value of approximately 385 psig. Valves 2HV-8701A and 2HV-8701B were both calibrated in September 1990 to approximately 379 psig. However, if a 4.77 psi static head correction factor is included the bistables set at 379 psig would actually be set at approximately 374 psig which is within the TS limit. The inspector noted the calibration procedures did not include a static head correction factor. The licensee does not include the correction because it is considered negligible since it is less than the criteria established for the inclusion of the correction based on instrument accuracy. The bistable set at 384 psig in 1989 would actually be set at 380 psig, which exceeds the TS limit. The licensee revised the Unit 1 and 2 calibration procedures as corrective action.

The inspector verified that the procedures were corrected to set the OPI bistable setpoints less than or equal to TS limits. This procedure inadequacy is not considered safety significant since the interlocks remained below the design pressure of the RHR system and the licensee's operating practices restrict opening the RHR suction valves above 350 psig indicated RCS pressure. The cause of these calibration errors was inadequate calibration procedures.

Calibrating the open permissive interlocks on 2HV-8702A at greater than 377 psig is a violation of TS 4.5.2.d.1.a. This licensee identified violation is not being cited because criteria specified in section VII.B of the NRC enforcement policy were satisfied. This violation is identified as NCV 50-424,425/92-07-04, Inadequate Calibration Procedure For RHR System Open Permissive Interlocks Results In TS Violation. The licensee is also preparing an LER on this event.

e. Containment Integrated Leak Rate Test

The inspectors walked through the preparations for the ILRT, observed a portion of the test, and reviewed the results of the test with the licensee. The ILRT was performed on April 19 in accordance with procedure 28329-2, Containment Integrated Leak Rate Surveillance Test. The test was successfully completed in 8.75 hours. Following the test a 4.5 hour verification test was performed which validated the ILRT. Also as part of the ILRT a visual examination of the accessible portions of the containment building was performed to determine if any conditions existed which would have affected the performance of the containment during an ILRT. No adverse conditions were identified. The inspectors had no further comment.

One non-cited violation was identified.

4. 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
29201332	Troubleshoot 2B Sequencer Timing Discrepancy
29103186	2HV5132 AFW Pump 2 Discharge SG-2 MOV PM
29100079	AFW Check Valve 2-1302-U4-116, Repair Seating Surface
29200761	Install and Rewire Cables Required Per DCP 92-V2N0054 To Delete RHR Auto Closure Interlock Feature & Replace With Control Room Alarms

b. Check Valve Pivot-Pin Inspection

On March 25, the licensee was performing procedure 28716-2, Westinghouse Style 'B' Check Valves ISI Surveillance, on Loop 2 ECCS accumulator check valve 2-1204-V6-080. Initial results indicated that valve 080 had failed the pivot pin check. This check is used as a means to inspect the disc-hanger integrity by applying a force directly on the pivot pin. The pivot pin is press fitted into the hanger assembly and as such is designed to exhibit no movement within the hanger assembly. Valve 080 is a 10" check valve and by procedure a force of 100 lbs ± 10 percent must be applied to the pivot pin to verify its integrity. In order to be acceptable the pivot pin movement must be less the .003 inches. During this particular test, valve 080 exhibited pivot pin movement greater than .003 inches. When the licensee subsequently evaluated the testing methodology, it was discovered, that due to the size of the hydraulic equipment used to apply the force, an actual force of 360 psi had been applied to the pivot pin rather than the required 100 psi. Due to the excessive force applied, the valve had failed its ISI, when in fact, it most probably would have passed if the correct pressure had been applied. The licensee then replaced that check valve disc and then successfully tested another accumulator check valve to confirm that the testing methodology had been corrected. Enhancements will be made to procedure 28716 to ensure the hydraulic testing equipment is properly used. The inspector had no concerns regarding licensee corrective actions.

c. MOVATS Testing During 2R2

During the current Unit 2 refueling outage, 2R2, the licensee has performed surveillance testing on a total of 65 Limitorque motor operated valves using procedure 26859-C, Static Testing of Motor Operated Valve Using MOVATS 3000 Analysis and Test System. This procedure provides a method of monitoring motor operated valve limit switch and torque switch actuation, spring pack deflection, and closing cycles of the valve. This revised testing methodology measures the actual thrust in both the open and close direction. Previous methodology measured the actual thrust only in the open direction while closing thrust was calculated based upon movement of the springpack. This new testing methodology was a result of a MOV Users Group (MUG) report which indicated that MOV diagnostic equipment that relied on springpack displacement to estimate stem thrust did not meet the accuracy claims of its vendors. This evaluation of MOV diagnostic equipment is discussed in NRC Information Notice 92-23, Results of Validation Testing of Motor-Operated Valve Diagnostic Equipment. Prior to the issuance of this Information Notice, the licensee met with their vendor, MOVATS, on March 5-6, 1992, to discuss revised testing techniques which would address concerns that had already been expressed by MUG. In addition to adopting the new testing methodology the licensee is in the process of evaluating previous test data on MOVs that have not yet been tested using the revised testing methodology. This evaluation will be performed at the licensee's corporate office.

The results from the 65 MOVs tested revealed that a total of eight indicated some amount of overthrusting. These overthrust discoveries were made possible by the new testing methodology. In four of these cases the licensee, after consulting Limitorque, determined that the MOV had an incorrectly rated springpack installed. The springpacks come from the vendor with no visible markings to indicate their rating. The licensee has replaced them with the proper spring packs. These incorrect springpacks were apparently installed either by Limitorque or Westinghouse and the MOVs have operated in that condition since startup of Unit 2. Of the eight cases noted of overthrusting none exceeded the maximum allowable overthrust. The licensee's evaluation has determined that an uncorrected overthrust condition could limit the life of the actuator due to fatigue. In three of these eight examples the licensee replaced the torque related components. The remaining MOVs were inspected or otherwise evaluated for potential damage to the valve or actuator with no damage being identified. After reviewing the summary results of the 2R2 MOVATS testing and discussing those results with the cognizant maintenance engineer, the inspector was satisfied that the licensee had taken appropriate corrective actions on those deficiencies identified during the testing.

No violations or deviations were identified.

5. Modifications (37828)

a. Steam Generator Level Tap Modifications

During the Unit 2 2R1 refueling outage in the fall of 1990, the licensee implemented a design change to relocate the SG narrow range level lower tap from the SG downcomer region to a point below the SG transition cone thus increasing the narrow range level span from 128 inches to 233 inches. Relocation of the level taps resulted in an increased band of indication which allowed adjustment of the low-low SG level reactor trip setpoint and provided additional operating margin. This additional margin enabled Vogtle to withstand a feed pump trip from 100 percent power without sustaining a reactor trip and minimized the effect of SG level shrink/swell phenomena due to feedwater flow rate changes at low power.

However, following completion of the design during 2R1, difficulty was encountered during level instrument calibration due to trapped non-condensable gases in the instrument lines caused by an upward slope in the capillary line from the new SG lower level taps to the transmitter. The lines sloped upward due to using the original capillary tube penetrations through the secondary shield wall rather than drilling new penetrations. After some difficulty the licensee was able to calibrate the Unit 2 SG level instruments and the unit subsequently operated with no level transmitter problems.

Due to the difficulties described above, during the current Unit 2 refueling outage, 2R2, the licensee is implementing DCP 92-V2N0086-0-1 to provide a continuous downward slope from the SG lower narrow range level taps to the installed delta P transmitters. The instrument sensing lines were routed through new core drills in the secondary shield wall. The transmitters were also lowered to a centerline elevation below the SG lower taps. The design basis for requiring that the capillary line exhibit a continuous downward slope is that if any non-condensable gas enters the capillary line, it will eventually migrate out of the line into the SG. The inspector reviewed the DCP and the accompanying safety evaluation and found them to be acceptable. A containment walkdown was also conducted of the work in progress on this design change. The inspector had no concerns either with the DCP or the work observed in containment. The same SG level tap modification was made on Unit 1 during 1R3 in 1991. New core drills for a downward capillary line slope were included which avoided the difficulties encountered on Unit 2.

b. RHR Autoclosure Interlock Deletion Modification

During the current Unit 2 refueling outage the licensee implemented DCP 92-V20054-0-1 to delete the RHR suction isolation valves (2HV-8701A&B and 2HV-8702A&B) autoclosure interlock. This DCP required a change to TS to delete the surveillance requirements for the interlock. TS surveillance requirements for the RHR open permissive interlock were also revised.

The basis for deleting the autoclosure interlock is to increase the reliability of the RHR system by reducing the possibility of an inadvertent closure of the RHR suction isolation valves due to RCS pressure spikes or spurious pressure signals. The autoclosure interlock was designed to close the RHR suction isolation valves if RCS pressure increased above the design pressure of the RHR system to reduce the possibility of an intersystem LOCA. A Control Room alarm was added per this DCP to alert operators if RCS pressure increases to 420 psig and either one or both of the RHR suction isolation valves in a train are not fully closed.

The inspector reviewed portions of the DCP and its safety evaluation and found it acceptable. The inspectors also accompanied the modification engineer on a walkdown of portions of the cable routing and termination locations used for the DCP. The inspector also observed cable terminations performed under MWO 29200761 and had no concerns regarding the DCP or installation.

c. Replacement of 4160/480 Volt Transformer

The licensee has experienced on-going problems with GE supplied non-1E 4160/480v transformers. Several of the transformer failures have resulted in plant transients. After implementing several modifications to the existing transformers, the licensee decided to replace several critical transformers. The licensee has defined a critical transformer as a non-1E transformer whose failure could cause a unit trip, however, these transformers do not supply safety related equipment required for safe shutdown or mitigation and control of accident conditions.

The design change replaces the exiting GE supplied core and coil assembly for transformers 2NB01X, 2NB03X, 2NB10X, and 2NB11X with core and coil assemblies supplied by ABB. The ABB supplied assembly is designed to be installed in the existing GE transformer cases. The new ABB assemblies are about fifty percent heavier than the existing assemblies. The design change has accounted for the new equipment loads. The replacement transformers also have a temperature monitoring system which measures the temperature in all three phases using a thermocouple in each 480 volt winding. A monitor displays the phase with the highest temperature.

The inspector reviewed portions of the DCP and the safety evaluation and observed portions of the transformer replacement. The inspector had no further comment.

No violations or deviations were identified.

6. Diesel Generator 2B Resolution of Failure To Load Event

On April 1, the licensee performed procedure T-ENG-92-05, Diesel Generator 2B Voltage Test, in an effort to recreate the 2B DG failure to load event which occurred on February 5, 1992 (IR 50-424,425/92-02). The purpose of T-ENG-92-05 was to parallel the 2B DG to the grid with the generator voltage 50 volts below the system voltage and to collect data. After initially closing the DG breaker VARS went to negative 2000. VARS were then adjusted to a negative 2600 when the low excitation alarm was annunciated and regulator control was lost. When the operators attempted to adjust the VARS more negative the VARS abruptly decreased to a negative 4100 and could not be adjusted further using the voltage control switch. These results were similar to those of the February 5 failure.

Silicon-controlled rectifier (SCR) firing waveforms were recorded during this test and reviewed by GPC Corporate, SCS, Bechtel and the excitation system designer. The SCRs function to shunt current away from the excitation field based on the control provided to them from the voltage regulator. Discussions with the designer and the review of the test data revealed that under certain excitation conditions the voltage regulator is unable through design to supply excitation to the generator field. Due to the sizing of the power potential transformers and current transformers, there exists a small area within the leading (negative) KVAR range of the generator capability curve within which the voltage regulator will not function. The field voltage is too low in this area to allow regulation to occur, thus shutting the SCRs off completely. The original generator capability curve provided by the vendor indicated no operational restraints within the curve. Normal operation is in the lagging (positive) KVAR range. The vendor was also not aware of the restraints within the operational curve.

The voltage regulator controls the excitation voltage for the generator. The field of the generator is a rotating electromagnetic field of fixed polarity. The strength of this field is controlled by the generator excitation and solid state voltage regulator. Once running, the generator is selfexciting. Initially, however, an external source of 125 VDC is necessary for field-flashing on each start of the DG. An under-excited condition can be initiated when the DG is paralleled to an energized 4160 VAC 1E bus. Procedure 14980-1/2, Diesel Generator Operability Test, requires that when the DG is being synchronized to the bus that generator voltage be slightly greater, not more than 50 volts, than the bus voltage prior to closing the DG output breaker. If the DG voltage is less than the bus voltage then the DG can be under-excited. If the DG voltage is sufficiently less than the bus voltage a point is reached where the voltage regulator is unable to cause the SCRs to fire and thus produce field excitation. In this condition the voltage regulator by design is unable to perform its regulating function. The voltage regulator is designed to receive a positive current from the DG current transformers. The output of the voltage regulator to the SCRs is also designed to operate with a positive current. If the CT current is negative, as would be caused by DG voltage being less than the bus voltage, the voltage regulator is essentially being asked to perform outside its design and the resultant excitation current is insufficient to cause the SCRs to fire. This phenomenon can only occur when the DG is operated in parallel with the normal supply tied to the bus. Upon a loss of normal bus voltage, the DG would operate in the Unit Mode and the problem described above would not apply. Since operation of the diesel in the emergency mode requires carrying normal plant loads which are inductive, which would produce a lagging (positive) KVAR situation, operability would not be affected.

In summary, the voltage regulator performs as designed, but a condition can occur when the generator is operating in parallel with the normal bus supply and generator CT current is negative rather than positive resulting in an inability of the voltage regulator to provide excitation. The DG can only enter the area of non-regulation while paralleled to the grid. Additionally, the generator must be paralleled in an alignment which would cause the generator to pick-up excessive negative KVARs upon closing of the generator output breaker. Excessive negative KVARs would be an amount relative to a particular KW level which would place the generator in the marginal excitation area.

The licensee plans to revise procedure 14980 to clarify the method of paralleling the DG and subsequent actions should the situation described above occur. Essentially, the operator would open the DG output breaker and resynchronize the DG to the bus. Also, the procedure would more clearly state how much generator voltage should be above bus voltage prior to closing the DG output breaker. The licensee will discuss this condition in future licensed operator training classes. The licensee also plans to review previously reported valid DG failures to determine if any can be classified as invalid failures based on the results of this evaluation. Finally, a REA has been generated to review the design calculations and develop a capability curve for the diesel generator with emphasis on the negative VAR region of the capability curve.

The licensee's persistent efforts to resolve this DG excitation problem are commendable. That persistence resulted in a better understanding of the operation of the DG excitation system and should prevent future occurrences of this type.

No violations or deviations were identified.

7. Review of Overtime Records

During this inspection period the inspector reviewed a sample of overtime records for members of the plant staff who perform safety-related functions to verify compliance with TS 6.2.2e, Plant Staff. The TS provides guidelines to limit the use of overtime. The inspector reviewed records for 24 operations personnel including SROs, ROs and nonlicensed personnel; and 45 mechanical, electrical, and I&C maintenance personnel including supervisors, foreman, and craft personnel. This review covered the period from February 29 through April 3, 1992.

One example was identified where a non-licensed operations supervisor worked more than 72 hours in a 7 day period. The inspector verified from documentation that this deviation from TS guidelines was authorized prior to exceeding 72 hours and it was in accordance with the requirements of licensee administrative procedure 00005-C, Overtime Authorization. Eight examples were identified where maintenance personnel, including four foreman and five craft personnel, worked more than 72 hours in a 7 day period. The inspector verified from documentation that eight of these deviations were authorized prior to exceeding the guidelines and in accordance with the requirements of procedure 00005-C. One deviation was documented after exceeding the guidelines which is inconsistent with procedure 00005-C, however, this overtime was verbally authorized prior to exceeding the guidelines. The inspector also verified that prior authorization, in all cases reviewed, considered the full duration for which TS guidelines were exceeded. The inspector reviewed the basis for approving excess overtime. The operations supervisor deviated from TS guidelines to establish continuous operations coverage to support LLRT coordination due to the unplanned early start of the U-2 refueling outage. Two maintenance foreman deviated from TS guidelines to provide coordination for 2B DG maintenance activities while the activities were on critical path. Two foreman and five electricians were approved for excess overtime to support extensive MOVATS activities.

Although several examples were identified where personnel had worked significant overtime to support outage activities, the inspector concluded that approval of the overtime was appropriate and found no evidence of abuse.

No violations or deviations were identified.

8. Refueling Activities (60710)

The inspectors monitored Unit 2 refueling operations in the control room, observed movement of and core placement of several fuel assemblies from the refueling bridge in containment and observed fuel movement at the spent fuel pool. The inspectors also observed visual inspection of several spent fuel assemblies and portions of core verification activities.

No violations or deviations were identified.

9. Followup on Previous Inspection Findings (92701) (92702)

a. (Closed) IFI 50-424,425/90-19-15, "Lack of Operator Guidance Concerning the LCO Actions Applicable During ESFAS Sequencer Outages."

An allegation indicated that the Operations Department incorrectly used a 72-hour shutdown requirement when one of the two ESFAS load sequencers was previously inoperable. It was also indicated that VEGP had taken no action to ensure that the past occurrences were identified and reported to the NRC as required by 10 CFR 50.73, despite newly acquired information that de-energizing an ESFAS sequencer required entry into the 1 hour limiting condition for operation (LCO) action requirements of TS 3.0.3. In addition, the possibility existed that the LCO for TS 3.0.3 (i.e., 7 hours to hot standby) were exceeded when the sequencers were previously deenergized for maintenance and testing. This concern was based on (1) the lack of a specific TS for the sequencers (2) the Operations Department historically linking the sequencer outages to the emergency diesel generator (EDG) LCO of TS 3.8.1.1.b (78 hours to hot standby), (3) a limited review of past maintenance work orders (MWOs) indicated the possibility of the sequencer being de-energized; and (4) comments by the engineering staff that the sequencers had been previously deenergized.

A review of applicable operator training material (System Description 8b for Engineered Safety Features System Sequencers) revealed that guidance has been provided associated with an inoperable diesel during ESF sequencer outages.

b. (Closed) VIO 50-424/90-19-13, "Failure to Establish or Implement Procedures for Required Activities."

By letter dated November 25, 1991, GPC responded to the Notice of Violation issued November 1, 1991. In the response, GPC denied Example 1 of the violation. The response was that the portion of the procedure referenced in the violation did not exist at the time of the event described in the violation. The NRC reviewed the additional information and agreed that this example did not constitute a violation. The procedure was later revised on May 10, 1990, to provide further guidance on deficiency card initiation. Accordingly, we will adjust our records to reflect that no violation of regulatory requirements occurred with respect to Example 1.

Georgia Power Company in their response to the second example of the violation stated that the violation occurred. The violation was of Administrative Procedure 00100-C associated with Temporary Change Procedure (TCP) 18028-C-7-90-1. The TCP was dated and signed with the date of the decision to void the procedure instead of the date of the actual signing. The inspectors reviewed the corrective actions taken by the licensee and that steps have been taken to avoid further similar violations.

10. Exit Meeting

The inspection scope and findings were summarized on April 24, 1992, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection findings identified. No dissenting comments were received from the licensee. The licensee identified as proprietary some material provided to the inspectors during this inspection.

Item No.	Description and Reference
NCV 424/92-07-01	Failure to Test ContainmentIsolation Valve Leads to TS Violation (paragraph 2.e)
IFI 424,425/92-07-02	Review and Followup of Significance of 2B Sequencer Timing Failure

	(paragraph 3.b)
IFI 424,425/92-07-03	Evaluation of ECCS Flow Balancing Data and Test Procedure Revisions (paragraph 3.c)
NCV 424,425/92-07-04	Inadequate Calibration Procedure For RHR System Open Permissive Interlocks Results In TS Violation (paragraph 3.d)

10. Abbreviations

ABB	Asea Brown Boveri
AC	Alternating Current
ACOT	Analog Channel Operational Test
AFW	Auxiliary Feedwater System
ATI	Automatic Test Insertion
CCP	Centrifugal Charging Pump
CIV	Containment Isolation Valve
CT	Current Transformer
DC	Deficiency Card
DCP	Design Change Package
DG	Diesel Generator
DMIMS	Digital Metal Impact Monitoring System
ECCS	Emergency Core Cooling System
ESF	Engineered Safety Features
ESFAS	Engineered Safety Features Actuation System
GE	General Electric Company
GPC	Georgia Power Company
gpm	Gallons per Minute
I&C	Instrumentation and Controls
IFI	Inspector Followup Item
ILRT	Integrated Leak Rate Test
IR	Inspection Report
ISI	Inservice Inspection Program
KVAR	Kilovolt ampere reactive
KV	Kilovolt
KW	Kilowatt
lbs	Pounds
LCO	Limiting Conditions for Operations
LER	Licensee Event Reports
LLRT	Local Leak Rate Test
LOCA	Loss of Coolant Accident
MFP	Main Feedwater Pump
MOV	Motor Operated Valve
MOVATS	Motor Operated Valve Actuator Testing System
MUG	Motor Operated Valve Users Group
MWO	Maintenance Work Order
NCV	Non-cited Violation

NPF	Nuclear Power Facility
NRC	Nuclear Regulatory Commission
NSCW	Nuclear Service Cooling Water System
OPI	Open Permissive Interlock
PA	Protected Area
P&ID	Piping and Instrumentation Diagram
PM	Preventive Maintenance
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
RCS	Reactor Coolant System
REA	Request for Engineering Assistance
Rev	Revision
RHR	Residual Heat Removal System
RO	Reactor Operator
rpm	Revolutions per Minute
SCR	Silicon-controlled Rectifier
SCS	Southern Company Services
SG	Steam Generator
SI	Safety Injection
SIP	Safety Injection Pump
SMA	Strong Motion Accelerograph
SNC	Southern Nuclear Company
SRO	Senior Reactor Operator
TS	Technical Specification
USS	Unit Shift Superintendent
UV	Undervoltage
VEGP	Vogtle Electric Generating Plant
VDC	Volts-Direct Current
VIO	Violation