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

Report Nos.: 50-321/94-11 and 50-366/94-11

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

Docket Nos.: 50-321 and 50-366 License Nos.: DPR-57 and NPF-5

Facility Name: Hatch Nuclear Plant

Inspection Conducted: April 17 - May 14 1994

Inspectors: P.H. Skinner for — 6/8/94
Leonard D. Wert, Jr., Sr. Resident Inspector — Date Signed

P.H. Skinner for — 6/8/94
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P.H. Skinner for — 6/8/94
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Approved by: Marvin V. Sinkule — 6/10/94
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SUMMARY

Scope: This routine resident inspection involved inspection on-site in the areas of operations including refueling floor activities, surveillance testing, review of maintenance activities including extensive work on an emergency diesel generator, drywell inspection, modifications, and review of open items. Also, a Unit 2 startup, shutdown, and subsequent restart was monitored.

Results: One violation and two non-cited violations were identified:

The violation addressed two examples in which the insulation on safety related equipment in the drywell was not installed as prescribed in drawings and instructions. While operability of the components was not adversely affected, it was considered significant in that the guidance on the applicable drawings was not followed. (paragraph 5).

A non-cited violation (NCV) was identified which involved two missed Technical Specification surveillances. Surveillance testing of several containment isolation valves was performed less frequently than required by the Inservice Test Program. Testing was completed several hours after the specified time interval. (paragraph 3b).

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A NCV involved the use of clear plastic on the refuel floor during refueling activities. (paragraph 2b).

During tours of the Unit 2 drywell at the end of the refueling outage, the inspectors identified that insulation material on chilled water piping was loose and not properly covered. While NRC Bulletin 93-02: Debris Plugging of Emergency Core Cooling Suction Strainers, was primarily directed at temporary sources of fibrous material in containments, the inspectors considered the uncovered insulation to be potentially significant sources of material which could also cause plugging of strainers. The insulation was repaired/covered prior to unit restart. (paragraph 5).

Numerous Control Room activities associated with the Unit 2 restart were observed. The inspectors noted strong operator performance including consistent use of procedures and good communications. Additionally, the inspectors observed extensive diagnostic and maintenance activities involving the 1B diesel generator. The inspectors concluded that the licensee's performance in identifying and correcting the governor equipment problems was appropriate. (paragraph 4b.)

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*J. Anderson, Unit Superintendent
D. Bennett, Chemistry Superintendent
S. Bethay, Hatch Licensing Manager, Southern Nuclear
*J. Betsill, Unit 2 Operations Superintendent
*E. Burkett, Supervisor Engineering Support
C. Coggin, Training and Emergency Preparedness Manager
*S. Curtis, Operations Support Superintendent
*D. Davis, Plant Administration Manager
*B. Duvall, Plant Engineering Supervisor
*P. Fornel, Maintenance Manager
*W. Flowers, SAER Acting Supervisor
G. Goode, Engineering Support Manager
M. Googe, Outages and Planning Manager
S. Grantham, Acting Training and Emergency Preparedness Supervisor
J. Hammonds, Regulatory Compliance Supervisor
E. Hopkins, Operations Shift Support Supervisor
W. Kirkley, Health Physics and Chemistry Manager
L. McDaniel, Acting Manager, Plant Administration
*B. McGinn, Security Operations Supervisor - Nuclear
*T. Metzler, Acting Manager Nuclear Safety and Compliance
C. Moore, Assistant General Manager - Operations
D. Read, Assistant General Manager - Plant Support
R. Reddick, Emergency Preparedness Coordinator
*J. Robertson Jr., Acting Manager PMMS
K. Robuck, Manager, Modifications and Maintenance Support
*H. Sumner, General Manager - Nuclear Plant
J. Thompson, Nuclear Security Manager
S. Tipps, Nuclear Safety and Compliance Manager
*P. Wells, Operations Manager

Other licensee employees contacted included technicians, operators, mechanics, security force members and staff personnel.

NRC Resident Inspectors

*L. Wert
*E. Christnot
*B. Holbrook

* Attended exit interview

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

2. Plant Operations (71707) (61710)

a. Operations Status and Observations

Unit 1 began the report period at 100 percent RTP. On April 29 power was reduced to 90 percent RTP for a short period of time to swap condensate booster pumps. Power was also reduced to 75 percent and returned to 100 percent on May 7 to perform main turbine valve testing.

Unit 2 began the report period in day 33 of the eleventh refueling outage with core reload in progress. Reloading was started and stopped intermittently to affect repairs and adjustments to the fuel handling equipment. Numerous restart activities were performed. Among these activities were LSFTs, Votes testing of MOVs, post modification testing, surveillances, post maintenance testing, and response time testing. On April 19, 1994, core reload was completed. Criticality was attained on April 28. The main generator was tied to the grid on April 30. Due to feed water line valve problems, the generator was taken off the grid and the reactor was manually scrammed the same day. Repairs to the feed water valve were completed, the reactor was started up with criticality being attained on May 3, and the main generator was tied to the grid on May 4. The unit attained 88 percent RTP on 6 May, but reduced power to 55 percent RTP for rod pattern adjustment. The unit attained 100 percent RTP on May 10, following fuel preconditioning.

Activities within the control room were routinely monitored. Inspections were conducted on day and on night shifts, during weekdays and on weekends. Observations included control room manning, access control, operator professionalism and attentiveness, and adherence to procedures. Instrument readings, recorder traces, annunciator alarms, operability of nuclear instrumentation and reactor protection system channels, availability of power sources, and operability of the SPDS were monitored. Activities associated with the two Unit 2 startups were closely monitored.

Control Room observations also included ECCS system lineups, containment and secondary containment integrity, reactor mode switch position, scram discharge volume valve positions, and rod movement controls.

Plant tours were taken throughout the reporting period on a routine basis. The areas toured included the following:

Reactor Building	Diesel Generator Building
Fire Pump Building	Intake Structure
Station Yard Zone	Turbine Building
Refuel Floor	Unit 2 Drywell

b. Refueling Floor Observations

The inspectors frequently observed refueling floor activities throughout the report period. Refueling activities were verified to be conducted in accordance with required procedures. Specifically, the inspectors observed that recent procedural revisions involving fuel bundle identification and locations were implemented. Also, the inspectors observed that the operators were completing the act[illegible] verify the fuel bundles were properly attached to the fuel [illegible]e prior to the bundle being lifted and moved.

During a routine tour of the refueling floor on April 18, the inspectors identified several examples of clear plastic material on the refueling floor. On the top of the RFTD's trash container was several small pie[illegible] of clear plastic which had apparently been used to wrap tape that [illegible] been used on the floor. This container is located only a f[illegible] from the SFP. The tape material should have been unwrapped prior to entry into the refueling floor area. Additionally, the inspector observed that workers used several clear plastic bags during work activities on the refueling floor. The inspector informed the RFTD and the material was promptly removed from the floor. The licensee has recently implemented a policy prohibiting the use of clear plastic on the refueling floor. A sign is prominently posted on the access door stating that the material is not to be ca[illegible]ed into the area. Workers have been trained on the revised pro[illegible]res, and management emphasized the upgraded controls during meetings. Section 4.2 of Procedure 51GM-MNT-002-0S: Maintenance Housekeeping and Tool Control, lists the plastic materials for use on the refueling floor. The list specifies that colored plastic materials are to be used. This violation is not being cited because criteria specified in Section VII.B of the NRC Enforcement Policy were satisfied. The violation was immediately corrected. The issue was logged in the refueling floor log and discussed with outage management. The inspectors are not aware of any other instances of clear plastic in use on the floor since the procedural controls were upgraded. The inspectors concluded that the violation would not have been expected to have been prevented by corrective action to a previous issue and that the violation was not willful. The inspectors noted that the procedural controls which were violated were enhancements which had been recently implemented by the licensee and are not specifically required by regulations. This violation is identified as NCV 321,366/94-11-03: Use of Clear Plastic On Refueling Floor.

c. Unit 2 CRD High Temperatures

Since May 7, three CRDs on Unit 2 have indications of elevated temperatures. CRD 26-27 indicated approximately 275 degrees F, CRD 34-35 indicated 300 degrees F and CRD 26-19 indicated 445 degrees F. The CRD high temperature alarm actuates in the CR at 250 degrees F. GE SIL 173, Control Rod Drive High Operating Temperatures, dated May 28, 1976 described possible causes, proposed corrective actions and

possible consequences due to high temperatures. The inspectors reviewed the SIL and discussed the CRD temperature problem with reactor engineering and operations. Engineering indicated that the most probable cause of the high temperatures was a plugged cooling water orifice. The SIL stated that temperatures in excess of 250 degrees F can shorten the CRD graphitar seal life and increase CRD drive maintenance, and temperatures of 350-550 degrees will result in a significant reduction in strength of the graphitar seals. Also, temperatures over 350 degrees F may result in a measurable delay in scram response times. A temperature increase to 400 degrees F could result in up to a 0.150 second increase in the 90 percent insertion time for an otherwise normal-performing CRD. The inspectors reviewed the temperature readings and determined the highest reading was for rod 26-19 at approximately 450 degrees F. The temperature appeared to be fluctuating slightly around this temperature.

The control rods were scram time tested during the week of May 2. The current scram time of rod 26-19, which has the highest temperature indication, was 3.101 seconds. This is well within the TS limits of less that 7 seconds. The postulated increase in scram insertion time of this rod would not result in any TS limit being violated. A discussion with operations indicated CRD temperature readings were being recorded on a hourly basis. Engineering is closely monitoring the temperature changes. Engineering is planning corrective action recommendations specified in the SIL. Attempts to unplug the cooling water orifice by flushing the CRDs will be initiated during any forced outage. Also, GE guidelines for CRD rebuild requirements are being considered.

The inspectors concluded that the increase in temperatures would not present a problem with control rod scram insertion times. There was considerable margin remaining prior to reaching or exceeding the TS scram insertion time requirement.

d. Unit 2 Bi-stable Flow

On 10 May, 1994, the Unit 2 control room operators detected reactor recirculation flow oscillations. The operators initially suspected flow oscillations to be associated with the scoop tube mechanism. Additional observations indicated the possibility of bi-stable recirculation flow. Inspection Report 50-321,366/93-13, documented a similar condition of bi-stable flow on the same unit. That report also documented the GE SIL 467 recommendations and the suggested actions for this condition. The SIL actions were completed and it was concluded bi-stable flow was occurring. Engineering had connected a chart recorder to monitor and record the recirculation flow changes. The inspectors independently reviewed the graphs dated May 11, 1994, that indicated oscillations. This graph indicated a step change in loop 2B flow from approximately 17,100 MLB/HR to 17,500 MLB/HR with the 2B recirculation MG set scoop tube locked in manual. When bi-stable flow oscillations occurred it

resulted in a change of approximately 2 to 3 MWe on the generator output and 6 to 9 MWt change on reactor power. The inspectors concluded that the indications being observed were consistent with the SIL information and the licensee was adequately monitoring the oscillations. The changes in reactor power were not safety significant and TS limits were not violated.

One NRC identified NCV was identified.

3. Surveillance Testing (61726) (61701)

a. Surveillance Observations

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, authorization to begin work, 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, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and systems restoration was completed.

The following surveillances were reviewed and witnessed in whole or in part:

1. 42SV-R43-012-2S: EDG 1B LOCA/LOSP LSFT
2. 57SV-C11-003-2S: CRD Accumulator Pressure and Leak FT&C
3. 34SV-C11-006-2S: CRD Withdraw Stall Flow Test
4. 34SV-E11-004-01: RHRSW Pump Operability
5. 43IT-OPS-004-0S: Dynamic MOV Testing (HPCI)
6. 34SV-C51-002-2S: APRM Functional Test
7. 57SV-C51-008-2S: IRM Calibration
8. 57SV-C11-004-2S: CRD Timing

During the observations, the inspectors noted that personnel consistently used procedures and communications appeared strong. The proficiency observed during some of the testing indicated that detailed preparation had been conducted prior to the work.

b. Missed TS Surveillances

During the week of May 2, NSAC notified the resident staff of two missed surveillances. One missed surveillance dealt with the Unit 1 Containment Purge, Vent, and Nitrogen System (T48). In November 1993, operators performing procedure 34SV-SUV-008-1S: Primary Containment Isolation Valve Operability, identified that seven T48 valves did not meet the acceptance criteria of the procedure and the IST program. The valve stroke times had changed by more than 50 percent from the previous test results. The valves closure times were less than the 5 second maximum closing time required by TS. The SS completed the Surveillance Program Data Base Revision Request forms as required by procedure 90AC-OAP-001-0S: Test and Surveillance Control. However, he incorrectly documented the increased surveillance testing frequency as being double the existing frequency. The actual IST program requirements for the containment isolation valves is to increase the testing frequency to a monthly interval. During the procedure review, the inspectors noted that the typical actions for the IST testing results was to double the testing frequency. Section 4.3, Special Requirements, of procedure 34SV-SUV-008-2S: Primary Containment Isolation Valve Operability, states the requirement to increase the testing frequency to once per month for valves with stroke times less that 10 seconds when the stroke times change more that 50 percent from the previous test. The requirement to change the frequency to monthly is also indicated as footnote (1), at the end of Attachment 1, where the new test data is recorded.

The completed Surveillance Program Data Base Revision request form was submitted for review and approval. An independent review also failed to identify that the incorrect surveillance frequency had been assigned. Consequently, the surveillance was successfully completed 4 times instead of 5 during the 5 month period between the period of December 1993, and April 1994. In all cases, the closing time requirements were considerably less than that required by TS. This error was identified by a non-licensed operator, during a procedure review prior to performing the surveillance in April 1994.

LER 1-94-004 was submitted May 9, 1994. The inspectors reviewed the LER and held discussions with NSAC management. The applicable surveillance and administrative procedures were reviewed. The inspectors concluded that personnel error on the part of one individual and a failure to conduct a proper independent verification by a second individual was the root cause of the missed TS surveillance.

The other surveillance involved the Unit 2 jet pump operability surveillance. The requirements in part, for this surveillance are that the procedure be performed prior to exceeding 25 percent RTP, following recirculation pump startup, and at least once per 24 hours thereafter. During the Unit 2 startup, before the unit exceeded 25

percent RTP, the surveillance was performed following recirculation pump startup. The procedure was also performed twice for the 24 hour thereafter requirement. However, an additional 24 hour surveillance requirement was exceeded by 2.5 hours beyond the specified time limit. The surveillance was immediately completed after it was recognized the time had been exceeded.

The inspectors reviewed the procedures and TS associated with both of these missed surveillances. Discussions were conducted with operations, NSAC and plant management. Corrective actions were reviewed and discussed with the appropriate management personnel. The corrective actions included counseling personnel involved in the issues, discussions with shift personnel to heighten their awareness and sensitivity to surveillance testing, review and verification, and initiation of actions to prevent recurrence. The inspectors verified the surveillances were immediately performed and the correct frequency specified.

The inspectors noted, during a review of this problem, that the new improved TS surveillance requirements for the jet pumps were changed. The surveillance will not be required to be performed during similar conditions when the improved TS are implemented. The surveillance will not be performed when RTP is less that 25 percent and not until 24 hours after exceeding 25 percent RTP. The inspectors concluded that for the existing plant conditions, which was less that 25 percent power, a delay of 2.5 hours in the performance of the procedure did not present a safety concern and had no adverse impact on safety.

The inspectors conducted a review of violations for the previous two years. The review was focused on examination of similar violations involving conditional TS surveillances and personnel errors. The inspectors identified one NCV, that occurred in November 1992, dealing with a conditional TS situation and involving personnel error. However, after an extensive review comparing the previous event with the two recent situations, the inspectors concluded the previous corrective actions should not have prevented these deficiencies. The inspectors concluded the licensee actions were appropriate. This will not be subject to enforcement actions because the licensee's efforts in identifying and correcting the violation meet the criteria in Section VII.B of the Enforcement Policy. The two failures to perform surveillances within their prescribed intervals are identified as NCV 50-321,366/94-11-02: Missed Technical Specification Surveillance Procedures.

One NCV was identified.

4. Maintenance Activities (62703)

a. Maintenance Observations

Maintenance activities were observed and/or reviewed during the reporting period to verify that work was performed by qualified personnel and that approved procedures in use adequately described work that was not within the skill of the trade. Activities, procedures, and work requests were examined to verify proper authorization to begin work, provisions for fire hazards, cleanliness, exposure control, proper return of equipment to service, and that limiting conditions for operation were met.

The following maintenance activities were reviewed and witnessed in whole or in part:

1. MWO 2-93-2179: 18 Month Preventive Maintenance on EDG 1B
2. MWO 1-93-1817: Vital AC Battery Supply 1R23-5008
3. MWO 2-94-1601: Repair Valve 2N21-F006A
4. MWO 1-94-1553: Repair Loose Wire In 1C71-P001
5. MWO 2-94-0455: High Vibration on 2T41-B003A (RHR/CS Room C Cooler)

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

b. 1B Emergency Diesel Generator

As part of the Unit 2 outage, the required 18 month preventive maintenance was performed on EDG 1B. Following maintenance activities and subsequent operability runs, the EDG experienced three separate overspeed trips. The events were as follows:

On April 23, procedure 42SV-R43-012-2S: Diesel Generator 1B LOCA/LOSP LSFT, was being performed. While performing section 7.2 of the procedure, which simulates a LOCA signal, EDG 1B tripped on overspeed as speed was increasing during the quick start. An LCO was entered for the inoperable EDG. Maintenance determined that the overspeed trip setting was too low and adjusted the setting.

On April 24, procedure 34SV-R43-005-1S: EDG 1B Semi-Annual Test, was performed. The EDG tripped while performing the quick start section of the procedure. Operability surveillance testing on the other EDGs was completed as required. Maintenance was again contacted to investigate the problem. A vendor representative was contacted to assist with the investigation. The operators observed that the governor did not appear to respond properly to engine speed. Maintenance replaced the governor and servo booster and the EDG was

started for the maintenance run. During the maintenance run, on April 25, EDG 1B was successfully started, however, the EDG output breaker would not close to tie the generator to its bus. Maintenance determined that the syncro-acceptor relay was defective. The relay was replaced and the EDG was successfully started and tied to the bus. The operability surveillances were satisfactorily performed and the EDG was determined operable. The LCO was terminated on April 25.

On April 26, the EDG again tripped on overspeed during the quick start section of procedure 34SV-R43-005-2S. Maintenance investigated this trip with vendor representative assistance. The governor was vented to ensure that air was not present. Compensation adjustments were performed on the governor. Following the adjustment, a quick start was performed on the EDG. Maintenance personnel, observing the test run, did not think the fuel racks were fully closed when the EDG started. The EDG was shutdown and preventive maintenance was performed on the fuel racks. Following this maintenance three additional quick starts were successfully performed on the EDG. The operability surveillances were again performed to prove 1B EDG operable.

Plant management initiated an ERT to investigate these EDG activities due to the number of EDG trips and additional reoccurring problems. The ERT investigated for root cause, common failure mechanisms and to make recommendations for corrective actions. Also, the ERT was to determine if the EDG should be considered operable even if the operability surveillances were successfully completed. On April 26, the ERT made a determination that the EDG should not be considered operable. The 24 hour run and hot restart surveillance that was in progress was terminated. Operations and maintenance personnel conducted additional investigations into the EDG problems. The EDG was started, tied to the bus and stopped several times during the investigation. No additional problems were identified during these investigations. All operability surveillances were completed. A 24 hour test run was successfully completed and the EDG was declared operable on April 27.

The ERT completed its investigation and communicated its findings and recommendations in an SOR. The team concluded that a post maintenance test run of the EDG should be included as part of the maintenance procedure. Also it was noted that improperly setting the governor compensation following maintenance effected the sequence of events.

During the inspectors' discussions with the licensee, the maintenance supervision indicated that there were several items that contributed to the problems associated with the EDG. The major problem was the setting of the governor compensator. Maintenance personnel and the vendor representative indicated that the compensator could only be set to a certain tolerance and that actual EDG testing was required for the final setpoint adjustment. An

additional contributor was that the EDG overspeed trip setpoint, which was within the acceptable band recommended by the vendor, had drifted toward the lower end of the acceptable band. The governor, governor oil, and servo had been changed, and these activities resulted in conditions that would require precise settings of the governor compensator. Also, maintenance personnel were aware that the temperature of the governor oil affected the response of the overspeed trip mechanism. This could explain the response of the EDG during different test conditions.

The inspectors monitored this problem. Observations were made during the testing and maintenance activities of the EDG from the CR and locally at the EDG. The inspectors reviewed many of the maintenance and testing procedures that were used during the investigation and testing process. Operations management provided close supervision and oversight. The system engineer was present to provide assistance and guidance. Maintenance supervision was present and provided specific attention to the activities. The inspectors observed that the maintenance personnel and operations were using procedures and no discrepancies were noted. The inspectors also reviewed the completed work package, MWOs, and completed procedures associated with the EDG maintenance.

The inspectors concluded that the operators provided proper attention to the operation of the EDG. Procedures were correctly used and supervision provided the necessary oversight. Maintenance procedures were reviewed and the inspectors noted that the adjustment and setting of the governor compensator was included. The adjustments were to be performed while the EDG was running. However, the maintenance procedure did not require a quick start and run to complete or verify the final adjustments of the compensator. It was not recognized that additional adjustments might be required for EDG startup until the performance of the operability surveillance by operations. Discussions with maintenance supervision indicated the maintenance procedures would be revised to require the EDG to be run to verify proper governor compensation setting prior to being turned over to operations for operability determination runs. Also, the actual overspeed trip setpoint for the EDG would be tracked and adjusted as necessary to maintain the trip settings near the upper end of the acceptable band. The inspectors noted that maintenance activities and governor compensation adjustments conducted on the other two Unit 2 EDGs did not require followup adjustments. The inspectors concluded that the maintenance procedural enhancements should prevent further overspeed tripping problems during operability runs.

The 1B EDG was placed out of service on May 12 to repair a loose dowel pin in the generator. (IR 50-321,366/94-08 discusses the dowel pin issue). An inspection after the performance of the monthly surveillance test had identified the loose pin. After repairs were completed, operations personnel commenced performing the monthly surveillance to meet Unit 1 TS requirements. On May 13, 1994, while

attempting to synchronize and tie the EDG to the grid, per the surveillance procedure, the generator output breaker would not close.

The licensee immediately established an ERT to gather facts, review activities and report conclusions, and recommendations to licensee management. The licensee started the 1B EDG on the morning of May 13, and determined that the speed control was at or very near the high speed stop, approximately 100 rpm below its previous setting. The licensee called in vendor representatives who determined that the cause of the problem was the speed spring which is internally mounted within the governor. A vendor representative informed the inspectors that if this spring is not properly seated in a new or rebuilt governor, this would result in the problems which the 1B EDG was experiencing.

The inspectors independently reviewed the licensee's operating logs and recent operating history of the diesel. The inspectors discussed the event with licensee and vendor personnel. The inspectors observed the post maintenance run of the EDG which was performed on May 14. The generator was tied to the grid, over a period of time raised to 3200 KW, and allowed to operate at this power for approximately one-half hour. During this operation the inspector observed the generator amps, engine crankcase vacuum, cylinder exhaust temperatures, field amps, engine speed, generator frequency, lube oil temperature, generator voltage, scavenger air pressure, and cooling jacket temperature. The inspector noted that all parameters appeared normal for 3200 KW.

The causes of the EDG 1B problems were conclusively attributed to the following:

- The internal component problem in the replacement governor caused the speed control for the engine to shift from the original setting, causing the 1B EDG to be inoperable. The governor was subsequently repaired and tested, and the EDG was proven operable.

- The failure of the output breaker to close involved the mechanical linkage that prevents a breaker which is not fully inserted from closing. The breaker was thoroughly inspected, and adjustments and lubrication was completed to correct the problem.

The inspectors determined that post maintenance test on the 1B EDG governor and breaker were adequately performed. After additional review of the issues involved, the inspectors concluded that plant maintenance personnel would not be expected to have knowledge of the mis-adjustment internal to the governor. The inspection, adjustment, and testing of the governor is conducted by the vendor.

c. Thermal Binding of A Unit 2 Feed Water to Reactor Valve

During startup of Unit 2 on April 28, 2N21-F006B, FW to Reactor valve, was opened as required by procedure, however, the 2N21-F006A valve would not open. Maintenance discovered that the 2N21-F006A valve was under a hydraulic lock. A problem with both of the FW valves sticking closed had been identified prior to 1988. Ta that time an REA (HT-7600) was submitted to SCS on the valve binding problems. A recommended action was to change the operating procedure to cycle the valves fully or partially during temperature decreases of approximately 50 degrees F when the valves are closed. However, the REA did not specifically address the problem of binding when the system temperature is increased with the valve closed. The valves are 18 inch gate valves with a split wedge seat. Due to this design the valve is susceptible to hydraulic locking when the valve temperature is increased or decreased with the valve closed.

The licensee discussed with the inspectors, their plan to continue the unit startup to approximately 20 percent power. The A FW valve remained closed and the B FW valve allowed the required condensate and FW flow to the reactor vessel. This allowed system observations and walkdowns to be completed to identify any additional areas of required maintenance. The inspectors concluded that the capacity of one FW injection valve was more than adequate for the low reactor power level operations. Following the power ascension to approximately 20 percent power, the unit was shutdown and maintenance activities were conducted.

To resolve the problem, SCS engineers recommended a 1/4 inch hole be drilled in the upstream side wedge on these valves. This would eliminate the hydraulic lock but would sacrifice one seat and not correct for thermal binding due to cooldown.

The inspector reviewed the MWOs and completed work packages for the maintenance activities. The inspectors determined that the FW valves to the reactor vessel were classified as non-safety relat ' valves. It was noted that QC inspections were conducted during parts of the maintenance activities. Discussions with QC management indicated this was an activity beyond their normal QC requirements, but due to the significance of this work, the licensee decided to perform QC activities on this work effort. The inspectors did not identify any concerns during this review.

No violations or deviations were identified.

5. Drywell Tour (62703)

The inspectors toured the Unit 2 drywell on April 20. Several significant deficiencies were noted:

The insulation on the SRVs was not installed in accordance with the guidance contained in the vendor manual drawing. The installed SRV

insulation covered some of the topworks portion of the valve assembly. Figure 14 of the vendor manual directs that insulation not be installed above the lower flange level of the topworks. To correct this condition, the licensee removed metal banding from around the insulation and moved it downward on the topworks. The inspectors also questioned the impact of the improper insulation on the valve's operation and was informed that the vendor had confirmed that operability was not affected.

The inspectors also identified that insulation was not installed on the steam leg piping to two reactor vessel level indication reference leg condensing pots. Drawing S-34325 B, indicated that insulation should be installed on the piping from the vessel nozzle up to 18 inches from the condensing pots. The inspectors also noted that GE SIL 470 recommended that licensees ensure that the steam leg insulation is in place and not deteriorated prior to each refueling outage startup. On one of the "heated" reference legs, the metal sheathing around the two small pipes was not connected as required. After identifying this observation to the licensee, the inspectors were informed that the absence of the insulation did not adversely affect the operation of the level instrumentation.

Although there were no adverse effect on the components involved, existing drawings were not complied with during maintenance activities on safety related equipment. This is identified as Violation 50-366/94-11-01: Insulation on Drywell Components Not Installed In Accordance With Drawings.

Additionally, the inspectors observed that the fiberglass insulation installed on the P64 (DW Cooling and Chilled Water), system piping had become significantly degraded. At numerous locations, the metal sheathing was not in place and torn/frayed insulation material was exposed. Some small pieces of the fiberglass material were noted on grating surfaces in the DW. After discussions with licensee management corrective actions was initiated to repair the degraded insulation. The inspectors noted that NRC Bulletin 93-02: Debris Plugging of Emergency Core Cooling Suction Strainers, notified licensees of the potential loss of net positive suction head for the ECCS systems from fibrous air filters or other temporary sources of fibrous material. Although the Bulletin was primarily directed at temporary sources of fibers, the inspectors considered this insulation to be a potentially significant source of fibrous material that could effect the ECCS strainers.

The inspectors also inspected the caulking material around the diameter of the DW floor. The material is installed between the concrete floor of the DW and the steel liner. The inspectors noted that the material was very soft and degraded. Numerous items had become impressed into the soft material. At some locations, pieces of the material were missing. The material had pulled away from the drywell liner and it appeared that moisture could travel down to the joining material. The inspectors discussed this observation with the licensee. The licensee informed the inspectors that an inspection had just been performed on the material by

an SCS engineer. The documentation indicated that he had noted the same deficiencies as the inspectors. The inspection had been performed due to a similar problem identified during the last outage on Unit 1. The inspectors reviewed MWO 2-94-1407 and a letter which documented the inspection results and recommendations. The inspectors concluded that the documentation adequately supported delaying repair activities until the next outage.

The inspectors also noted that a significant quantity of duct tape, paper, and scaffolding nails were present. At that time the licensee was still in the process of cleaning up the DW in preparation for restart and procedures for closeout of the DW had not been completed. The inspectors noted that those procedures are general in nature and do not contain detailed guidance regarding permanently installed insulation material.

On April 25, the inspectors conducted another inspection of the DW to observe the general condition and cleanliness of the DW and to view the insulation repair. The inspectors verified that the insulation on the SRVs had been properly repositioned and the reactor water level instrument steam leg piping had been insulated. The inspectors identified several areas where the fiberglass insulation on the chilled water system piping was still in need of repair. The inspectors also identified several additional areas in the DW where the condition of the insulation was questionable. The inspector found two small hand tools and observed a considerable amount of debris. During this time plant personnel were inspecting the DW and collecting debris. The inspector discussed the insulation concerns and the general condition of the DW with the outage director and DW coordinator. The AGM-PO conducted a tour of the DW to view the general conditions and specific condition of the insulation. There were several areas identified where the condition of the insulation did not meet his expectations. Replacement or repair of the insulation was conducted prior to startup.

One violation was identified.

6. Modifications (37700) (37828) (71707)

The inspectors continued to review and observe many of the ongoing modification activities, especially for Unit 2. The inspectors observed specific activities associated with various DCRs. Observations included; initial installation activities of some DCRs, activities performed during the 40 percent to 60 percent modification complete milestones on other DCRs, and the final installation activities and post modification testing on other DCRs.

The inspectors concluded from the assessment that the modifications observed were installed in accordance with approved procedures, instructions, and design drawings. The inspectors will continue to assess additional DCRs and post modification testing during the next reporting period.

No violation or deviations were identified.

7. Inspection of Open Items (92700) (92701)

The following items were reviewed using licensee reports, inspections, record reviews, and discussions with licensee personnel, as appropriate:

a. (Closed) LER 50-321/93-10: Less Than Adequate Procedure Results in Unplanned ESF Actuation. This LER addressed an event which occurred when Unit 1 was in Hot Shutdown, all rods inserted, reactor pressure at 75 psig, and no vacuum in the main condenser. As part of the corrective actions the licensee stated that the procedure would be revised to include cautioning the user about tripping channels and requiring that the tripped channels be reset. The inspectors reviewed the revisions to procedure 34SV-B21-001-1S and 2S. Based on the review of the revisions to these procedures, this LER is closed.

b. (Closed) LER 50-321/93-11: Component Failure Results in Partial Group 1 PCIS Actuation. This LER was issued to document a partial Group 1 PCIS actuation when one of eight MSIVs closed during the performance of calibration procedure 57SV-CAL-005-0S, GE NUMAC Logarithmic Radiation Monitor Calibration. As part of the corrective actions the licensee installed light emitting diodes on both the Unit 1 and Unit 2 control boards, which constantly monitor the electrical continuity of both solenoid valves on each MSIV. Based on the installation of the continuity monitoring LEDs and the operators utilization of these indications, this LER is closed.

8. Exit Interview

The inspection scope and findings were summarized on May 17, 1994, with those persons indicated in paragraph 1 above. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

Item Number	Status	Description and Reference
50-366/94-11-01	Open	VIO - Insulation On Drywell Components Not Installed In Accordance With Drawings, paragraph 5.
50-321,366/94-11-02	Closed	NCV - Missed Technical Specification Surveillance Tests, paragraph 3b.
50-321,366/94-11-03	Closed	NCV - Use Of Clear Plastic On Refuel Floor, paragraph 2b.

9. Acronyms and Abbreviations

AGM-PO- Assistant General Manager - Plant Operations
AGM-PS- Assistant General Manager - Plant Support
APRM - Average Power Range Monitor
ARP - Alarm Response Procedure
BWR - Boiling Water Reactor
CFR - Code of Federal Regulations
CR - Control Room
CRD - Control Rod Drive
DC - Deficiency Card
DCR - Design Change Request
DW - Drywell
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EHC - Electro Hydraulic Control
ERT - Event Review Team
ESF - Engineered Safety Feature
EST - Eastern Standard Time
F - Fahrenheit
FSAR - Final Safety Analysis Report
FT - Functional Test
FT&C - Functional Test and Calibration
FW - Feedwater
GE - General Electric Company
HP - Health Physics
HPCI - High Pressure Coolant Injection System
I&C - Instrumentation and Controls
IFI - Inspector Followup Item
IN - Information Notice
IR - Inspection Report
IRM - Intermediate Range Monitor
IST - Inservice Testing
KW - Kilowatts
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LOSP - Loss of Offsite Power
LSFT - Logic System Functional Test
MG - Motor Generator
MOV - Motor Operated Valve
MSIV - Main Steam Isolation Valve
MSLRM- Main Steam Line Radiation Monitor
MWe - Megawatts Electric
MWt - Megawatts Thermal
MWO - Maintenance Work Order
NCV - Non-Cited Violation
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
NSAC - Nuclear Safety and Compliance
PCIS - Primary Containment Isolation System
PEO - Plant Equipment Operator

P&ID - Piping and Instrumentation Drawing
PM - Preventive Maintenance
PMMS - Plant Modifications and Maintenance Support
PRB - Plant Review Board
PSIG - Pounds Per Square Inch
PSW - Plant Service Water System
QC - Quality Control
RB - Reactor Building
RCIC - Reactor Core Isolation Cooling System
RCS - Reactor Coolant System
REA - Request for Engineering Assistance
RFTD - Refueling Floor Technical Director
RHR - Residual Heat Removal
RHRSW- Residual Heat Removal Service Water System
RPS - Reactor Protection System
RTP - Rated Thermal Power
RX - Reactor
SAER - Safety Audit and Engineering Review
SBGT - Standby Gas Treatment
SCS - Southern Company Services
SFP - Spent Fuel Pool
SIL - Service Information Letter
SOR - Significant Occurrence Report
SOS - Superintendent of Shift (Operations)
SPDS - Safety Parameter Display System
SRB - Safety Review Board
SRO - Senior Reactor Operator
SRV - Safety Relief Valve
SS - Shift Supervisor
STA - Shift Technical Advisor
TS - Technical Specifications