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

Report Nos.: 50-321/95-27 and 50-366/95-27

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 1 and 2

Inspection Conducted: December 3, 1995 - January 6, 1996

Inspectors:	For R. W. Wright Bob L. Holbrook, Sr. Resident Inspector	2/1/96 Date Signed
	For R. W. Wright Edward F. Christnot, Resident Inspector	2/1/96 Date Signed

L. King, Reactor Inspector, Paragraph 3.0 through 3.6.

Accompanying Inspector: James A. Canady

Approved by:	Pierce H. Skinner Pierce H. Skinner, Chief, Project Branch 2 Division of Reactor Projects	2/1/96 Date Signed

SUMMARY

Scope: Inspections were conducted by resident inspectors and regional inspectors in the areas of plant operations which included operation of the Unit 2 Reactor Core Isolation Cooling System from the remote shutdown panel, Unit 1 Reactor Recirculating Water Pump 1B trip, self assessment, review of licensee overtime policy and controls, review of Unit 1 automatic scram, key plant management changes and inspection of open items; maintenance which included Unit 2 Low Pressure Coolant Injection Inverter 2B, Emergency Diesel Generator 1B inspection, Unit 2 2C Plant Service Water Pump maintenance, surveillance activities, cold weather preparations, poor maintenance practices during valve packing activities, and inspection of open items; engineering which included Unit 1 remote shutdown system logic test, cooling tower fill material removal and upgrade, and inspection of open items; and plant support which included routine monitoring of plant support activities and observations and review of the Unit 2 hydrogen injection test.

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The inspectors conducted backshift inspections on the following dates: December 3, 9, 10, 26, 1995; January 4, and 6, 1996.

Results: One non-cited violation and one inspector followup item were identified:

Plant Operations:

Deficiencies were not identified during the inspectors review of routine activities (paragraph 2.2).

Testing of the Unit 2 Reactor Core Isolation Cooling System from the remote shutdown panel was successful. The evolution was adequately supervised and controlled. Technical oversight provided by engineering personnel was very good (paragraph 2.3).

Operator performance during Unit 1 Reactor Recirculating Water Pump 1B trip was very good. The inspectors concluded that intentionally entering the conservative buffer zone of the region of potential instability during the initial phase of the transient was reasonable. However, increased knowledge of reactor core power response to the start of a Reactor Recirculating Water Pump would have prevented the second entry into the same region. Both entries into the buffer zone presented very little safety significance. Licensee management's oversight as well as maintenance and engineering's response to trouble shoot and conduct repairs were very good. The Event Review Team's root cause determination and recommendations for corrective actions were excellent (paragraph 2.4).

The inspectors initial review of the licensee's self assessment activities did not identify any deficiencies (paragraph 2.5).

Review of the licensee's overtime policy and controls disclosed that overtime was not routine and it was requested and approved in accordance with the administrative control procedure. The usage of overtime was adequately controlled (paragraph 2.6).

The plugging of servo filters that caused reactor scrams and operational and plant challenges has been a recurring problem. Although the licensee previously completed several actions to correct the problem they were not successful. This item was identified as Inspector Followup Item 50-321,366/95-27-01: Recurring Electro-Hydraulic Control Servo Filter Plugging Causing Reactor Scram. Operations management was present following the Unit 2 scram and provided adequate oversite. Operator performance for recovery actions was very good. Maintenance and engineering personnel provided good support to operations to troubleshoot and correct the problem (paragraph 2.7).

Maintenance:

The inspectors observed that personnel consistently used procedures, exhibited strong communication practices, and were proficient with the tasks during routine maintenance activities (paragraph 3.1).

The inspectors did not identify any specific deficiencies or concerns during the observations of routine surveillance activities (paragraph 3.2).

The inspectors identified several deficiencies with the licensee's cold weather preparation. The inspectors considered these deficiencies to have little safety significance at the time of the inspection. However, lower outside temperatures could increase the significance of these deficiencies (paragraph 3.3).

The licensee's actions for deficiencies associated with valve packing problems were satisfactory. Valve stem damage was observed on the Unit 2 Low Pressure Coolant Injection Valve on October 10, 1995. Licensee investigations revealed other deficiencies and three additional valves were repacked to correct packing deficiencies. This was identified as Non-cited Violation 50-321,366/95-27-02: Maintenance Deficiencies During Valve Packing Activities (paragraph 3.4).

Engineering:

The Unit 1 Remote Shutdown Panel Logic Test was performed in a controlled manner, under proper supervision, using pre-test briefings and with adequate technical oversight (paragraph 4.1).

Actions taken to replace or remove the damaged cooling tower fill material to reduce the possibility of a plant scram or transient were appropriate (paragraph 4.2).

The inspectors did not identify any specific concerns or deficiencies during the reviews and observations of design change request activities (paragraph 4.3).

Plant Support:

Security access controls were satisfactorily maintained; Radiological Control Area boundaries were properly posted; high radiation areas were appropriately identified; and Fire Protection valves monitored were in their proper position (paragraph 5.1).

The Unit 2 hydrogen injection test was well planned and implemented. The licensee was proactive with respect to protecting the reactor vessel internals (paragraph 5.2).

REPORT DETAILS

Acronyms used in this report are defined in paragraph 7.0.

1.0 Persons Contacted

Licensee Employees

*J. Anderson, Unit Superintendent
*K. Breitenbach, Engineering Supervisor
D. Crowe, Hatch Licensing Manager, Southern Nuclear
D. Bennett, Chemistry Superintendent
*J. Betsill, Operations Manager
*R. Burns, Plant Operator
C. Coggins, Engineering Support Manager
*S. Curtis, Operations Support Superintendent
D. Davis, Plant Administration Manager
D. Dees, Operations Shift Supervisor
*W. Flowers, Safety Audit and Engineering Review
*P. Fornel, Performance Team Manager
O. Fraser, Safety Audit and Engineering Review Supervisor
E. Gibson, Reactor Engineering Supervisor
R. Godby, Maintenance Superintendent
*R. Grantham, Acting Training and Emergency Preparedness Manager
J. Hammonds, Regulatory Compliance Supervisor
*W. Kirkley, Health Physics and Chemistry Manager
J. Lewis, Training and Emergency Preparedness Manager
*C. McDaniel, Acting Plant Administration Manager
R. McGinn, Security Operations Supervisor
T. Metzler, Acting Manager Nuclear Safety and Compliance
*C. Moore, Assistant General Manager - Plant Support
*J. Payne, Senior Engineer
R. Reddick, Emergency Preparedness Coordinator
*P. Roberts, Outages and Planning Manager
*J. Robertson, Acting Manager, Modifications and Maintenance Support
D. Smith, Chemistry Superintendent
H. Sumner, General Manager - Nuclear Plant
J. Thompson, Nuclear Security Manager
*S. Tipps, Nuclear Safety and Compliance Manager
*J. Watts, Operations Shift Supervisor
P. Wells, Assistant General Manager - Operations
*T. White, Fix It Now (FIN) Team Member

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

2.0 Plant Operations (40500) (71707) (71711) (92901) (93702)

2.1 Plant Status

Unit 1 began the report period at 100% RTP. On December 8, the unit began end of core life coastdown. The early coastdown was due to the eight control rods being fully inserted to suppress neutron flux in the areas of fuel leakage. On December 16, Unit 1 Reactor Recirculating Water pump 1B tripped and power was eventually decreased to about 35% RTP. A control rod pattern adjustment was initiated and the B fifth stage FW heater was removed from service to increase RTP. RTP was attained on December 20. On January 4, 1996, Unit 1 automatically scrammed from approximately 75% RTP due to high reactor pressure following TCV closure. At end of the report period the Unit was at 20% RTP.

Unit 2 began the report period at 95% of the new 2558 Mwt power limit. The unit attained the new RTP with 865 Mwe on December 3, 1995. The unit operated at 100% RTP for the remainder of report period with the exception of scheduled power reductions for routine testing.

2.2 Routine Inspection Activities

Activities within the control room were routinely monitored. 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. 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.

Deficiencies were not identified by the inspectors. The observed activities were conducted as required by the licensee's procedures. The complement of licensed personnel on each shift met or exceeded the minimum required TS. Observed operating parameters were verified to be within TS limits.

2.3 Operation of the Unit 2 RCIC from the RSDP

As part of the licensee's corrective actions for deficiencies identified on the Unit 2 RSDP on November 9, the licensee operated the RCIC system from the RSDP to verify proper operation. The activity was controlled by SP procedure 34SP-111495-DC-1-2S, Operation of RCIC From the Remote Shutdown Panel, Revision 0. On December 6, the inspectors reviewed the SP procedure, observed the pre-activity briefing, the RCIC system operation at the RSDP and the post activity briefing.

The procedure shifted partial control of the RCIC system from the CR to the RSDP. The RCIC turbine trip and throttle valve was then closed and electrically disabled by racking the breaker out. The RCIC turbine was started by manually opening the trip and throttle valve locally. Once the turbine started, the automatic controller took control. Operators raised the RCIC pump output to 400 gpm at 1035 psig discharge pressure using the redundant controls located on the RSDP. The RSDP controls were successfully tested in manual and in automatic.

The inspectors concluded the SP test was performed successfully. The RCIC system flow and pressure observed during the operation were within the procedural acceptance criteria. The evolution was adequately supervised and controlled. Technical oversight provided by engineering personnel was very good.

2.4 Unit 1 Reactor Recirculating Water Pump 1B Trip

At 2:33 a.m., on December 16, Hatch Unit 1, RR water pump 1B tripped. Immediately after the 1B RR pump trip, operators observed reactor core plate differential pressure at 0 psid and jet pumps (11 thru 20) indicating between 60 and 95 with 10 psid swings. The operators inserted control rods to decrease power and load. Operators decreased speed of the operating RR pump, which indicated slightly over 100% speed demand to reduce power.

Due to the unusual jet pump dp indications and RR speed indicating over 100% speed demand, operators rapidly decreased the speed of the operating RR pump. Operators intentionally entered the region of potential instability of the reactor power versus flow map and began increased monitoring for core instabilities. Core flow and control rods were adjusted and the region was exited in approximately 38 minutes.

The cause of the trip was determined to be a resistor in the voltage control system of the MG set. Maintenance personnel replaced the failed resistor with a temporary equivalent resistor.

The 1B RR pump tripped twice during startup attempts. Maintenance discovered a blown fuse in the voltage regulator control circuit. They believe the catastrophic failure of the resistor caused the fuse to blow. The fuse was replaced and the RR pump was successfully started and placed in service on December 17.

Operations entered the region of potential instability of the reactor power versus flow map following RR pump 1B startup. Control rods were inserted and the potential instability region was exited after approximately 21 minutes.

The inspectors responded to the event, investigated the problems and observe licensee recovery actions. The inspectors reviewed Unit 1 TS 3.4.1 and procedure 34AB-B31-001-1S, Trip of One or Both Reactor

Recirculation Pumps, or Recirculation Loops Flow Mismatch, Revision 5, and verified the region of potential instability (the reactor power versus flow map) that required a reactor scram was not entered. The region of potential instability entered was a 5% conservatism buffer area added by the licensee. The inspectors also determined the "operation not allowed region" of TS figure 3.4.1-1 was not entered.

The inspectors discussed entering the region of potential instability with operations personnel. The operators stated their concern was for the protection of plant equipment. That was based upon jet pump dps indicating between 60 and 95 with 10 psid swings and RR pump 1A speed indicating over 100% speed demand. The inspectors reviewed procedure 34GO-OPS-005-1S, Power Changes, Revision 16. Section 5.2 allowed entering the region of potential instability to protect plant equipment that might adversely impact plant safety. The inspectors were informed that engineering discussed the jet pump and core dp indications with GE. GE personnel stated the indications were to be expected and was not a problem.

The inspectors discussed the failed resistor that initiated the transient with maintenance and engineering personnel. The resister problem was identified in GE SIL 586 in January 1995. The licensee had developed a MWO work package to replace the resistors in all RR pumps at the first opportunity. The resistors were replaced in the Unit 2 RR pumps during fall 1995 refueling outage.

Maintenance and engineering personnel also identified a potential problem with the breaker racking mechanism for the 1B RR MG set motor breaker. The end of the racking mechanism bar was slightly worn. This problem could have prevented the breaker from being fully racked in. The end of the racking bar mechanism was designed to mechanically slip when the breaker was fully racked in. Maintenance and engineering personnel determined this problem did not cause the RR pump trip. The racking mechanism bar was replaced and the breaker was tested and returned to service. The inspectors discussed the worn racking bar problem with maintenance and engineering personnel. Inspection of the racking mechanism bar was not part of the routine PM program. Engineering personnel stated that inspection of the racking bar mechanism would be evaluated for possible inclusion into the routine PM program.

The 1A RFPT speed control did not respond properly while removing the 1B RFPT from service. Maintenance personnel identified that a retaining key in a lever arm of the speed control was sheared. Also, the minimum flow valve for the 1B RFPT opened rapidly. This, in conjunction with the sheared key, caused a reactor water level transient. As a result the 1A RR pump ran back in speed. The operators took immediate manual control to restore reactor level. Similar reactor water level transients, due to RFPT minimum valve operation, are documented in IR 50-321,366/95-18. Maintenance personnel replaced the sheared key, the RFPT was tested and returned to service. The RFPT minimum flow valve response problem is scheduled to be repaired during the next refueling outage.

The inspectors review of procedures and operator actions did not identify any performance deficiencies. However, as part of the licensees ERT recommendations, several procedures were identified for possible enhancement. One item under review was the number of procedures required to be used concurrently during the transient.

The inspectors concluded operator performance during the transient was very good. The operator action to take immediate manual control of FW to restore reactor level probably prevented a reactor scram. The inspectors considered this operator action a demonstration of excellent performance and attention to detail.

The inspectors concluded that intentionally entering the conservative buffer zone of the region of potential instability during the initial phase of the transient was reasonable and allowed by procedure. However, increased knowledge of reactor core power response to the start of a RR pump would have prevented the second entry into the same region. Additional margin from the region of potential instability could have been established prior to the RR pump start. The inspectors concluded both entries into the buffer zone presented very little safety significance.

The inspectors concluded licensee management oversight as well as maintenance and engineering's response to trouble shoot and conduct repairs were very good. The ERT root cause determination and recommendations for corrective actions were excellent.

2.5 Self Assessment

The inspectors began inspection preparations and conducted initial reviews of portions of the licensee's self assessment programs. The inspectors reviewed the TS and Quality Assurance Manual requirements. The initial reviews also included recent QA audits, audits completed in 1995, and the preliminary 1996 audit schedule.

The inspectors verified audits were conducted in all major functional areas as required by the licensee's quality assurance manual. The inspectors confirmed some audits were conducted by personnel outside the GPC organization. Other audits were supplemented with personnel from outside the licensee's parent organization and from different plants from within the organization.

No deficiencies were identified. The inspectors will continue to review the licensee's self assessment.

2.6 Review of Overtime Policy and Controls.

The inspectors performed a review of the licensee's overtime policy and implementation. Section 5.0 of the TS and Procedure 30AC-OPS-003-0S, Plant Operations, Revision 15, established the policy, requirements, and responsibilities for the use of overtime. The procedure referenced the TS and designated applicable managers as the approving authority for any deviations that exceeded limitations. The inspectors reviewed overtime records for plant employees that conducted safety related work. The licensee applied identical controls to overtime during both outage and non-outage activities.

The inspectors observed that overtime was not routine and was requested and approved in accordance with the administrative control procedure. The inspectors concluded that the usage of overtime was adequately controlled by the licensee.

2.7 Unit 1 Automatic Scram

On January 4, 1996, the inspectors were informed that Unit 1 had automatically scrammed.

An inspector proceeded to the site to assess the problem and observe licensee recovery actions. The inspector discussed the scram with licensee management, and operations personnel. The inspector was informed that operators observed that the number 1 TBV was fully open and TCVs number 2 and 4 were fully closed. TCV number 4 was already in the expected closed position due to decreased reactor power from end of core life coastdown conditions. Operators manually reduced reactor power to approximately 75% RTP using RR flow. A short time later operators observed that all three TBVs were open and the reactor automatically scrammed. Operations personnel later determined the scram was due to high reactor pressure.

The inspector confirmed conditions requiring ECCS system actuation did not occur and SRVs did not actuate. Reactor water level decreased to approximately 0 inches (TAF is -165 inches) and was recovered by the normal FW system. A PCIS group 2 isolation occurred as expected and was later reset. The inspector observed that the plant was in a stable condition and no major equipment problems existed. Operator actions for scram recovery actions were very good. Supervisory oversight was evident; applicable procedures were used; and communications were clear and concise.

Operations personnel suspected a problem with plugging of the EHC servo filters for the TCVs. GE personnel reported to the site to assist in the investigation. Operations management also initiated an ERT to investigate the root cause of the EHC problems and make recommendations for corrective actions. GE and maintenance personnel inspected the TCV servo filters and determined all four filters were plugged. This caused the TCV valves to go closed causing a reactor high pressure scram. The servo filters for the turbine stop and intercept valves were also inspected and indications of severe plugging were not observed. Samples of the material found on the TCV filters were sent to a laboratory for analysis to identify the substance and determine its origin. Licensee personnel stated that some type of fibrous material and clear gel substance was detected.

The licensee developed a SP procedure to change the servo filters while the unit was on line. During startup the filters were changed about every two hours. Following startup the filters will be changed weekly. Inspection of the filters during unit startup revealed that some black substance was present. However, the licensee stated that they believed that was a normal usage breakdown of the EHC fluid. Plugged filters were replaced as necessary to mitigate the problem.

Plugging of servo filters is a recurring problem. Unit 1 scrammed in May, 1992, when all four TCVs shut, and power was reduced in November of the same year when the number four TCV closed due to being plugged. In June 1994, problems were identified with EHC pump discharge filters becoming plugged. At that time maintenance identified that the filters were covered with a black soot or tar-like substance. The previous instances are documented in IR 50-321,366/92-12, 92-32, and 94-13. The problems associated with the first two previous instances were contributed to filters that were not compatible with EHC fluid. The licensee determined that this problem was not similar to the previous problems.

The inspectors held discussions with the ERT members, maintenance, engineering and operations personnel concerning this issue. The licensee completed several activities to correct the recurring problem. During the last Unit 1 refueling outage the EHC system was drained, flushed and cleaned. The presence of a similar black substance was identified in the system. The servo filters were changed numerous times. Although the actions were completed the corrective actions were not successful. EHC problems continued to cause reactor scrams and presented operational and plant challenges.

The inspectors concluded that the initiation of the ERT to investigate the problem and determine the root cause was appropriate. Operations management was present following the scram and provided adequate oversight. Maintenance and engineering personnel provided support to operations to troubleshoot and correct the problem. The inspectors will review the sample analyses and long term corrective actions when they become available. This item is identified as IFI 50-321,366/95-27-01, Recurring EHC Servo Filter Plugging Causing Reactor Scram.

2.8 Key Plant Management Changes.

On January 2, 1996, the following plant management changes were announced: Harvey Nix, General Manager - Nuclear Support retired and was replaced by Dennis Reed, Assistant General Manager - Plant Support. Terry Moore, Assistant General Manager - Operations assumed the position of Assistant General Manager - Plant Support, and Pete Wells, Operations Manager assumed the position of Assistant General Manager - Operations. Joe Betsill, Unit 2 Operations Superintendent assumed the position of Operations Manager, Curtis Coggins, Manager of Training and Emergency Preparedness assumed the position of Manager Engineering and was replaced by John Lewis who recently returned from temporary duty at INPO. Glenn Goode, who was the manager of engineering, began temporary duty at INPO.

2.9 Open Items

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

(Closed) LER 50-366/95-03: Reduction in Main Condenser Vacuum Prompts a Manual Reactor Scram.

This LER was issued following a Unit 2 manual scram on September 2, 1995. The manual scram was initiated due to decreasing condenser vacuum in the main condenser. Details of the problem are documented in IRs 50-321,366/95-18 and 95-22. Based upon the inspectors' review of the licensees' actions, this LER is closed.

One IFI was identified.

3.0 Maintenance (61726) (62703) (92902) (93702)

3.1 Maintenance Work Activities

Maintenance activities were observed and reviewed during the reporting period to verify that work was performed by qualified personnel and that procedures adequately described work that was not within the skill of the trade. Activities, procedures, and work requests were examined to verify 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:

MWO 2-95-3625: Unit 2 LPCI Inverter Maintenance

The 250 volt DC breaker, which supplies power to the 2B LPCI inverter output was removed for inspection. A leaky dashpot was replaced. The breaker was cleaned, bench tested for tripping, and the dashpot time was adjusted. The breaker was reinstalled. The inspectors also observed the cleaning and tightening of all connections on the inverter. The batteries in the control circuit to the inverter were replaced. The inverter was tested and put back in service.

MWO 1-93-3812: EDG 1B Maintenance Inspection Activities

The 1B Emergency Diesel Generator was removed from service and the stator windings were inspected using a fiberscope. This inspection was to determine if any of the fiber spacers that separate the generator stator windings were loose. A review of these problems are documented in IR 50-321,366/94-27. It was observed that at least one fiber spacer was missing. The inspectors discussed the missing spacer with licensee personnel who conducted the EDG inspection. Maintenance personnel stated that this problem was identified in the past and engineering had authorized operation of the diesel until a later date when the stator could be removed and repairs made. A one hour surveillance run of the diesel was satisfactorily completed. A visual inspection was then made of the wooden dowels that help secure the rotor laminations. The diesel was rotated and a visual inspection was made of the rotor which looked for dowels that might have come loose. No dowels were found to have come loose and the diesel was returned to service.

MWO 2-95-3540: Unit 2 2C Plant Service Water Pump Maintenance Activities.

On December 14, the inspectors observed a one year PM on the 2C Service Water Pump. The pump had been in standby service and on the night shift the oil had been changed and megger readings taken in accordance with procedure 52IT-MEL-003-06, High Potential and Megger Testing of Electrical Equipment and Cables Revision 7. The required polarization index was 2.0 and the test showed a polarization index of 1.6. The pump was run for three hours on the day shift to improve the megger readings or polarization index. The pump was then shut down to take new readings. The inspectors observed the tagout of the 4160 volt breaker and the meggering of the windings. The Polarization Index reading was greater than 4.0. The service water pump was returned to standby. Discussions with the electricians indicated that this was not an unusual occurrence if the pump had been shut down for a long period of time. PMs are done on the motor heaters but apparently because of the humid environment they are not able to prevent low readings when the pumps have been secured for long periods. The normal testing is done when the pump is secured and before the oil is changed. The inspectors concluded that running the pump to improve the polarization index did not present a pump operability concern.

The inspectors observed that personnel consistently used procedures, exhibited strong communication practices, and were proficient with the tasks.

3.2 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. Witnessed tests were inspected to determine that procedures were available; test equipment was calibrated; prerequisites were met; tests were conducted according to procedure; test results were acceptable and system restoration was completed. The following surveillance was reviewed and witnessed in whole or in part:

34SV-R43-002-1S: Diesel Generator 1B Monthly Test

The inspectors observed surveillance testing of the 1B Emergency Diesel Generator which was run from Unit 1. When the EDG was secured the dowel pin inspection was completed.

The inspectors did not identify any specific deficiencies or concerns.

3.3 Cold Weather Preparations

The inspectors continued to monitor licensee preparations for cold weather conditions using procedure 52PM-MEL-005-0S and DI-OPS-36-0989N, Cold Weather Checks. Initial inspection activities for cold weather checks are documented in IR 50-321,366/95-26. Plant tours of selected areas were conducted. The early morning tours were performed when the outside temperature was approximately 25°F. The inspectors noted deficiencies involving three heat traces indicating as not being on, a door and a louver not fully closed in the fire pump building, and the possibility that the fire pump building space heater thermostats may need adjustments.

The inspectors considered these deficiencies as having little safety significant at the time of the tours. However, lower outside temperatures could increase the significance. These deficiencies were discussed with licensee personnel. Maintenance personnel stated they would evaluate actions to correct the problems.

3.4 Maintenance Deficiencies During Valve Packing Activities.

On October 30, maintenance workers observed that the LPCI inboard injection valve, 2E11F015B, had stem damage above the gland flange. Operations personnel were notified and a MWO was initiated to correct the problem. The valve was repaired, VOTES tested and a LLRT completed on November 4, 1995.

The inspectors initiated a review of licensees activities involving the valve. Work packages and MWOs were reviewed for work activities going back to early 1995. Operations personnel identified a second problem with the same valve on November 12. The second problem involved a failed valve stem coupling (see URI 50-321,366/95-26-02, Valve Failures Involving Stem Couplings and Valve Packing Configurations). The URI identified two specific concerns. The inspectors followup review of the concern associated with valve failures involving stem couplings is documented in paragraph 4.4 of this report.

Following the identification of the galled stem maintenance, personnel initiated a repair plan to correct the problem. An ERT was initiated to investigate the problem, determine root causes and make recommendations for corrective actions.

The inspectors discussed the problem with licensee management, maintenance personnel, refueling outage coordinators and ERT members. The ERT did not identify a definite cause of the galled stem. However, they identified several possible causes. These included, debris located in the packing gland area, improper packing configuration at the gland area, and possible side loading from the valve angled orientation. The ERT concluded that any one or a combination of the problems could have caused the damaged stem.

Several maintenance activities were completed on the valve during the fall refueling outage. The activities included DCR 94-34 which drilled the disc for GL 89-10 issues. Other GL 89-10 issues were also addressed at this time. Also, 18 and 36 month PMs were completed. Additionally, the spring pack cartridge cap was drilled and several other maintenance activities were completed. The valve was repacked during these activities. This work occurred between November 13 and November 24, 1995. These maintenance activities were conducted by contract personnel under the supervision of the PMMS department.

The inspectors reviewed procedure 52CM-MME-001-S, Repacking Valves and The Adjustment of Valve Packing, Revision 10, which was used to repack the valve. Attachment 4 of the procedure, Valve Packing Data Sheet, listed the required packing configuration to correctly repack the valve. The packing configuration required the top composite ring to be matched with beveled packing gland. This was not the correct configuration. Maintenance and engineering personnel stated that composite rings and bushing rings are not recommended for use with a beveled packing follower or with beveled stuffing box bottoms. In this case the valve was packed incorrectly using a composite ring with a beveled packing gland. The wrong data package was apparently used to develop the valve packing data sheets. The data sheets used were from the previous revision of the procedure.

There were other deficiencies identified with the current revision of the procedure. The procedure required the user to complete a survey data sheet for mechanical information about the valve. However, the procedure did not provide guidance for the use of the information. Also, the procedure did not require the user to inspect the lantern ring to determine if it was beveled or flat. In addition, the survey data sheets were computer generated. The computer softwear was not designed to address a beveled or flat gland configuration. The type of packing to use for this condition was left up to skill of the craft.

As part of the licensee's corrective actions, about 177 Unit 2 valves were reviewed or inspected to determine if any may have similar packing problems. Approximately 45 valves that were either safety related or important to safety were further reviewed. The licensee identified 8 potential valves with less than desired packing configurations. Of these 8 valves, 2E11F015A, LPCI inboard isolation valve was inspected and repacked immediately. A less than desired packing configuration was identified.

The licensee initiated MWOs to address the remaining seven suspected valves. All seven valves were found to have a beveled packing follower. Three valves, that had a beveled packing follower in combination with a composite packing ring on top were repacked. The valves were:

2E11F009 Shutdown Cooling Inboard Isolation

2B21F019 Main Steam Line Drains to Main Condenser Isolation

2E21F005A Core Spray Loop A Inboard Isolation

The inspector concluded that the corrective actions were timely in that the inspections and the less than desired configurations were corrected by November 10. The ERT also recommended that procedure 52CM-MME-001-0S be revised to flag the importance of matching the packing follower with the packing configuration. The licensee informed the inspectors that the procedure was in the revision process and would be revised prior to use. The inspectors will review the revised procedure when available.

The inspectors concluded that the lack of some procedural details as well as other deficiencies contributed to the improperly packed valves and subsequent valve failure. Debris found in the valve packing gland area demonstrated lack of attention to FMEC processes.

The inspectors concluded that the plant status (refueling outage) during the time the valves were out of service for maintenance activities decreased the significance of the problem and allowed significant opportunities for repair. The licensee's outage safety assessment of redundant systems for the plant conditions remained at the acceptable level.

The inspectors conducted a review of licensee performance for the past two years for similar occurrences. On July 7, 1995, Unit 1 HPCI valve 1E41F003, failed due to a galled stem. Contract personnel failed to follow procedure and did not properly pack the valve. Details of this problem are documented in IR 50-321,366/95-16, and LER 50-321/95-06. The inspectors concluded that, although some circumstances were similar, the corrective actions for the July 7, problem would not have prevented the latest problem. This is identified as NCV 50-321,366/95-27-02: Maintenance Deficiencies During Valve Packing Activities.

3.5 Inspection of Open Items

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

(Closed) LER 50-366/95-04: Excessive Leakage Identified on Secondary Containment Bypass Valves.

This LER addressed a failed LLRT of two valves, 2G11F003 and F004, which are associated with the drywell equipment and floor drain sumps. TS requirements for all bypass leakage paths is 544 ACCM. The actual measured leakage for the F003 valve was 17,858 ACCM and the F004 was greater than 30,000. Valve 2G11F003 was refurbished and F004 was replaced. Both valves were re-installed with an improved composite packing design. The valves were retested and left with essentially zero leakage. Based on the inspectors review of the licensee's actions, this LER is closed.

(Closed) URI 50-321,366/95-26-02: Valve Failures Involving Stem Couplings and Valve Packing Configurations.

The URI documented two specific concerns. The first concern associated with valve packing configurations resulted in valve stem galling. This rendered an ECCS valve inoperable. This specific concern of the URI is closed based upon the issuance of NCV 50-321,366/95-27-02, identified in paragraph 3.4 above. The second concern involving stem couplings is addressed in paragraph 4.4 of this report.

One NCV was identified.

4.0 Engineering Activities (37551) (92700) (92903) (93702)

4.1 Unit 1 Remote Shutdown System Logic Test

The inspectors reviewed and observed a test of the Unit 1 remote shutdown panel systems. The activities were controlled by SP procedure 42SP-120195-PP-1-1S, Unit 1 Remote Shutdown System Logic Test, Revision 0. The test was performed to ensure that the logic for the remote shutdown system was functional. The test consisted of 4 attachments. Attachment 1 tested the logic for RHRSW pumps 1B and 1D, attachment 2 tested the RHR pump 1B and PSW pump 1B, attachment 3 tested selected RHR system valves, and attachment 4 tested the RCIC systems. The inspectors observed that this was a logic system test only. Breakers were racked out and equipment was not energized during the test. One deficiency was identified with a blown fuse. This prevented testing the logic for SRV 1G. The fuse was replaced and the test was completed.

The inspectors concluded the test was performed in a controlled manner, under proper supervision, using pre-test briefings and with adequate technical oversight.

4.2 Cooling Tower Fill Material Removal and Upgrade

The inspectors documented in IRs 50-321,366/95-06, 95-22 and 95-23, a Unit 2 scram and other problems concerning cooling tower fill material. The unit scram was caused by the collapse of damaged fill material. A severe icing incident in 1989 damaged the fiberglass fill material and the "j" hooks that helped secure the fill material.

Due to the cooling tower configuration, the collapse of fill material from only six of sixty cooling tower cells would result in a condition that may cause a plant transient. These cells are located at the discharge of the cooling towers. The collapsed material would block the tower discharge screens and cause a reduction in cooling water flow through the main condensers.

The inspectors were informed that part of the licensees' corrective action was to remove or replace the damaged fill material in the six most critical cells. The inspectors observed that the fill material was removed or replaced prior to the Unit 2 refueling outage startup. The inspectors discussed the work activity with engineering personnel and were informed that the new fill material was a different type. The new material is made of stainless steel and does not use fiberglass "J" hooks.

The inspectors concluded that the licensee's actions to replace or remove the damaged fill material to reduce the possibility of a plant scram or transient was appropriate.

4.3 Modifications

The inspectors continued to review and observe the ongoing modification activities. The review included DCR packages and DCR implementation for some of the activities. These reviews included 10 CFR 50.59 review, unreviewed safety question criteria, required testing and job task activities. Among the DCRs reviewed were:

DCR	DESCRIPTION
95-35	Parallel Power Feed
95-47	EDG 1B Series Conversion

The inspectors did not identify any specific concerns during the reviews and observations.

4.4 Open Items

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

(Closed) URI 50-321,366/95-26-02: Valve Failures Involving Stem Couplings and valve Packing Configurations.

The URI documented two specific concerns. One concern, valve stem galling, resulted in rendering an ECCS valve inoperable. This concern is addressed in paragraph 3.4 above.

The second concern involved failed valve stem couplings. The inspectors observed and reviewed portions of the licensee's activities involving modifications and repairs of the valve stem couplings. Modifications were required for both Unit 2 LPCI inboard injection valves, 2E11F015A and F015B. A problem was identified on November 12, when operations personnel opened 2E11F015B and did not observe flow indication through the valve. A physical check of the valve identified a coupling failure. The coupling was used to couple the roller ball valve operator screw stem to the valve screw stem. The solid pin used to pin the coupling to the roller ball stem had sheared, the threads on the roller ball stem and on the inside of the coupling had stripped, and the coupling pulled apart. This prevented the valve wedge, or gate, from leaving the valve seat and effectively keeping the valve closed.

The failed coupling was solid and had been pinned and torqued to the stems at 2000 ft-lb torque. With vendor assistance, a new type of coupling was fabricated. The modified coupling has three parts, a solid piece, an upper jam nut and a lower jam nut. The roller ball stem and the valve stem were threaded into the solid piece, butted up against each other with a thin teflon piece inserted between them. The upper and lower jam nuts were threaded onto each side of the solid piece. The coupling was then torqued to the stems at 4000 ft-lb and was also pinned to the stems.

Coupling modification and VOTES testing were completed on the Unit 2 F015B valve. The LLRT and procedure 34SV-E11-002-2S, RHR Valve Operability, were performed and the valve declared operable on November 17. The Unit 2 F015A valve was then tagged out for coupling modification. On November 18, the modification and valve testing were completed and the valve declared operable.

The inspectors observed that the roller ball guide tube, located internally to the valve operator, for the F015B valve had also failed. This failure allowed some of the steel roller balls to be loose inside the valve operator.

The inspectors concluded, based on observations, reviews and discussions with licensee personnel, that the failure was most likely caused by the valve wedge being jammed into the seat by a very high closing force. This high force was due to the torque switch setting of the valve motor operator. When the valve operator was energized to open the valve the wedge would not initially leave the seat. The opening force, which in the initial valve operation is a twisting force, became so large that it overcame the 2000 ft-lb of torque and twisted the roller ball stem. This sheared the pins, stripped the threads, and may have also damaged the roller ball guide tube. The licensee and vendor stated that the new coupling design and torquing increase to 4000 ft-lb should correct the problem.

The inspectors observed that all activities were controlled using applicable procedures, continuously supervised, and with adequate technical support.

Based upon the inspectors' review of the licensee's actions, the portion of this URI concerning valve failures involving stem couplings is closed.

(Closed) LER 50-366/95-05: Personnel Error Results in Automatic Initiation of EDGs

(Closed) LER 50-366/95-06: Personnel Error Results in Automatic Start of EDG 1B

The above LERs were issued to address two unplanned starts of EDGs that occurred during testing activities. Details of the problems and the issuance of NCV 50-366/95-23-03: Inadvertent ESF Actuations During Testing, are documented in IR 50-321,366/95-23. Based upon the inspectors' reviews of the licensee's actions and the issuance of the NCV, these LERs are closed.

No violations or deviations were identified.

5.0 Plant Support Activities (71750)

5.1 Routine monitoring of Plant Support Activities

Security, health physics and other plant support activities were routinely observed and monitored during the report period. These activities included plant security access controls, locked high radiation area doors, proper radiological posting, personnel frisking upon exiting the RCA, and status of various FP equipment. The observations and monitoring were performed in conjunction with the conduct of other inspection activities.

The inspectors concluded that security access controls were satisfactorily maintained; RCA boundaries were properly posted; high radiation areas were appropriately identified; and FP valves monitored were in their proper position.

5.2 Unit 2 Hydrogen Injection Test

As part of the licensees' activities to protect the reactor vessel internals, a hydrogen injection test was performed at flows up to 50 scfm. IR 50-321,366/95-23 documented the inspectors review of DCR 93-59, Install Incore Stress Monitoring Instrumentation, during the recent Unit 2 refueling outage. The hydrogen injection test was controlled by SP procedure 63SP-110695-YM-1-2S, Stress Corrosion Monitoring Test. The test began on December 9, and was completed on December 14. The test varied hydrogen injection flow from 0 to 50 scfm. The test also included water chemistry monitoring and radiation surveys at various plant locations during increased hydrogen flows.

The inspectors reviewed the applicable procedures, monitored part of the test activities and discussed the test results with GE and plant personnel. The licensee reviewed the test results and determined that 40 scfm was the optimum flow rate for Unit 2.

The inspectors concluded that test planning and implementation, management attention and HP coverage during the test activities were very good. The inspectors concluded the licensee was proactive with respect to protecting the reactor vessel internals.

No violations or deviations were identified.

6.0 Exit

The inspection scope and findings were summarized on January 9, 1996, by the SRI with those persons indicated by an asterisk in paragraph 1. An interim exit was conducted on December 15, 1995. The inspectors described the areas inspected and discussed in detail the inspection results. A listing of inspection findings is provided. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Type	Item Number	Status	Description and Reference
IFI	50-321,366/95-27-01	Open	Recurring EHC Servo Filter Plugging Causing Reactor Scram (paragraph 2.7).
NCV	50-321,366/95-27-02	Closed	Maintenance Deficiencies During Valve Packing Activities (paragraph 3.4).
LER	50-366/95-03	Closed	Reduction in Main Condenser Vacuum Prompts a Manual Reactor Scram (paragraph 2.9).
LER	50-366/95-04	Closed	Excessive Leakage Identified on Secondary Containment Bypass Valves (paragraph 3.5).
URI	50-321,366/95-26-02	Closed	Valve Failures Involving Stem Couplings and Valve Packing Configurations (paragraphs 3.5 and 4.4).
LER	50-366/95-05	Closed	Personne Error Results in Automatic Initiation of EDGs (paragraph 4.4)
LER	50-366/95-06	Closed	Personnel Error Results in Automatic Start of EDG 1B (paragraph 4.4)

7.0 Acronyms

ACCM - Actual Cubic Centimeter
CFR - Code of Federal Regulations
CR - Control Room
DC - Direct Current
DCR - Design Change Request
DP - Differential Pressure
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EHC - Electro-hydraulic Control
ERT - Event Review Team
ESF - Engineered Safety Feature
FW - Feedwater
FMEC - Foreign Material Exclusion Control
FP - Fire Protection
ft-lb- Foot pound
GE - General Electric Company
GPC - Georgia Power Company
gpm - gallons per minute
HP - Health Physics
HPCI - High Pressure Coolant Injection
IFI - Inspector Followup Item
INPO - Institute of Nuclear Power Operation
IR - Inspection Report

KW - Kilowatts
LER - Licensee Event Report
LLRT - Local Leak Rate Test
LPCI - Low Pressure Coolant Injection
MG - Motor Generator
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
PM - Preventive Maintenance
PMMS - Plant Modification and Maintenance Support
psid - pounds per square inch differential
psig - pounds per square inch gauge
PSW - Plant Service Water System
QA - Quality Assurance
GL - Generic Letter
RCA - Radiological Control Area
RCIC - Reactor Core Isolation Cooling
RFPT - Reactor Feedwater Pump Turbine
RHR - Residual Heat Removal
RHRSW- Residual Heat Removal Service Water
RPS - Reactor Protection System
RR - Reactor Recirculation
RSDP - Remote Shutdown Panel
RTP - Rated Thermal Power
SAER - Safety Audit and Engineering Review
scfm - standard cubic feet per minute
SIL - Service Information Letter
SP - Special Purpose
SPDS - Safety Parameter Display System
SRI - Senior Resident Inspector
SRV - Safety Relief Valve
TAF - Top of Active Fuel
TBV - Turbine Bypass Valve
TCV - Turbine Control Valve
TS - Technical Specifications
URI - Unresolved Item
VIO - Violation
VOTES- Valve Operation Test and Evaluation System