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

Report Nos.: 50-321/95-22 and 50-366/95-22

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: September 3 - September 30, 1995

Inspectors: FOR R. W. Wright 10/24/95
Bob L. Holbrook, Sr. Resident Inspector Date Signed

FOR R. W. Wright 10/24/95
Edward F. Christnot, Resident Inspector Date Signed

Accompanying Inspector: James A. Canady

Approved by: Pierce H. Skinner 10/25/95
Pierce H. Skinner, Chief, Date Signed
Project Branch 2
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection involved inspection in the following areas: plant operations, maintenance, engineering, plant support activities, and inspection of open items. The inspectors conducted backshift inspections on the following dates: September 3-4, 9-10, 17, 23, and 24-30, 1995.

Results: One violation with two examples of failure to follow procedure and one poor work practice were identified.

Operations:

The first example of the violation for a failure to follow procedure occurred during control rod movements. Operators inserted a control rod to a location not specified in the procedure. The inspectors identified the most recent problem as another example of poor operator performance and inattention to detail. This continued poor operator performance, with respect to activities that affect reactivity, is a concern (paragraph 2.e).

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The second example of the violation occurred when control room personnel failed to initiate and maintain an annunciator control sheet to identify, label and implement compensatory actions for a problem annunciator for a safety related component from March 7 to September 7, 1995 (paragraph 2.f).

Inspection activities during preparation for Unit 2 refueling did not identify any significant discrepancies. The inspectors concluded that management's attention to detail for plant risk, and oversight of critical activities was very good (paragraph 2.b).

The inspectors concluded that management's safety perspective for general refueling activities on Unit 2 was very good. The outage safety assessment for verification of safety equipment redundancy was routinely stressed. Management had placed special emphasis on Health Physics related activities, personnel error reduction, oversight of contractor activities, and management expectations (paragraph 2.c).

Maintenance:

The inspectors concluded that the recent problems with all four Unit 2 Residual Heat Removal Service Water Pumps were isolated events and could not have been predicted. Although maintenance did not determine a root cause for the 2A pump problem, the inspectors concluded that maintenance and engineering support to operations for pump repairs and testing was timely and appropriate (paragraph 3.d).

Engineering:

Engineering support to maintenance and operations for activities associated with the 600 volt bus 1D undervoltage and load shed was very good (paragraph 4.b).

The inspectors concluded that poor work practices by contract maintenance personnel resulted in incorrect gasket installation in some safety related equipment. The inspectors also concluded that the Event Review Team conducted a thorough and comprehensive investigation of the problem. Their root cause determination and assessments were excellent (paragraph 4.b).

Plant Support:

The inspectors concluded that the elimination of the security guard post at the drywell entry and refueling floor during refueling activities did not lessen the effectiveness of the security plan (paragraph 5.a).

The inspectors concluded that management's attention to Health Physics related issues was very good. Personnel and tool monitoring as well as overall minimizing personnel dose were among the licensees primary focus (paragraph 5.b).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*J. Anderson, Unit Superintendent
D. Crowe, Hatch Licensing Manager, Southern Nuclear
D. Bennett, Chemistry Superintendent
J. Betsill, Unit 2 Operations Superintendent
*K. Breikenbach, Engineering Supervisor
C. Coggin, Training and Emergency Preparedness Manager
*S. Curtis, Operations Support Superintendent
*D. Davis, Plant Administration Manager
*P. Fornel, Maintenance Manager
*O. Fraser, SAER Supervisor
E. Gibson, Reactor Engineering Supervisor
R. Godby, Maintenance Superintendent
*G. Goode, Engineering Support Manager
*S. Grantham, Acting Training and Emergency Preparedness Manager
*J. Hammonds, Regulatory Compliance Supervisor
*P. Hardison, Licensed Control Room Operator
*W. Kirkley, Health Physics and Chemistry Manager
*J. Lewis, Unassigned Manager
R. McGinn, Security Operations Supervisor
T. Metzler, Acting Manager Nuclear Safety and Compliance
*C. Moore, Assistant General Manager - Operations
J. Payne, Senior Engineer
D. Read, Assistant General Manager - Plant Support
R. Reddick, Emergency Preparedness Coordinator
*P. Roberts, Outages and Planning Manager
*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, supervisors, operators, maintenance personnel mechanics, security force members and staff personnel.

NRC Resident Inspectors

*B. Holbrook
E. Christnot

Accompanying Inspector

*J. Canady

* Attended exit interview

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

2. Plant Operations (71707) (60705) (60710)

a. Operations Status and Observations

Unit 1 began the report period at 100% RTP. The unit operated at that power level for the remainder of the report period with the exception of scheduled power reductions for routine testing.

Unit 2 began the report period in a forced reactor shutdown following a loss of condenser vacuum due to cooling tower damage. A reactor startup was initiated on September 3, and maximum coastdown power of 86% was attained on September 6. A manual power reduction was initiated on September 22. A manual scram was initiated from about 30% RTP at 1:01 a.m. on September 23, to begin the 12th refueling outage.

Activities within the control room were routinely monitored. Inspections were conducted on day and 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. 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	Radwaste Building
Unit 2 Condenser Area	

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.

b. Preparation for Unit 2 Refueling Activities

The inspectors conducted a review of licensee preparations for the Unit 2 refueling outage. The inspectors reviewed selected refueling procedures and administrative requirements to verify their adequacy for refueling activities. The inspectors reviewed procedure 42FH-ERP-012-OS: New Fuel and New Channel Handling, Revision 5, and

Revision 5, and observed work activities in progress. The inspectors verified the activities were conducted in accordance with procedural requirements. The inspectors observed the communication methods between the refuel bridge and the CR and concluded they were satisfactory.

The inspectors reviewed QC records and verified personnel conducting new fuel inspections met the required training and qualifications. The qualification was based upon a current medical and eye examination, prior education, GE specific fuel inspection training, and OJT.

The inspectors verified through interviews of contractor and key licensee personnel, and direct observations of activities in progress that a clear understanding of administrative and TS requirements for refueling activities existed.

The inspectors concluded that management's attention to detail for plant risk, planning and scheduling and oversight of critical activities was very good. The inspectors did not identify any specific concerns.

c. General Refueling Activities.

The inspectors observation of operator actions for general refueling activities included, unit power reduction, manual scram from 30% RTP and scram recovery actions. The inspectors verified that selected TS surveillances required for unit shutdown and refueling were current. The inspectors verified that administrative controls and instructions pertaining to refueling activities were clearly understood by operations personnel. The inspectors noted that operations management was present and provided appropriate oversight of critical activities.

The inspectors reviewed procedure 42FH-ERP-014-OS: Fuel Movement, Revision 11, and verified the procedural requirements were being met. The inspectors noted that this was the first time operators used a lap top computer as an aid to verify and track individual fuel moves.

The inspectors attended the ALARA briefing, conducted by HP personnel, in preparation for the initial condenser bay entry. Operations, maintenance, engineering, and HP personnel, made the entry to identify components in need of repair. The inspectors noted that HP seemed very knowledgeable of existing radiation levels in the condenser bay area and provided suggestions for avoiding unnecessary dose.

The inspectors noted that licensee as well as contractor personnel had a heightened awareness for HP related activities. This included personnel monitoring requirements, personnel and tool frisking, and RCA boundaries.

The inspectors concluded that management's safety perspective was very good. The outage safety assessment for verification of safety equipment redundancy was routinely stressed. Management had placed special emphasis on HP related activities, personnel error reduction, oversight of contractor activities, and ensuring managements expectations were met. The inspectors did not identify any specific concerns.

d. Equipment Clearance Verification

The inspectors reviewed procedure 30AC-OPS-001-0S: Control of Equipment Clearances and Tags, Revision 14, and walked down two clearances to verify breakers, control switches, dampers and valves were positioned as required by the equipment clearance sheets. One clearance was initiated to align secondary containment configuration for fuel handling activities. The second clearance aligned equipment and components associated with the 2A EDG for maintenance activities.

The inspectors did not identify any specific concerns.

e. Mispositioned Control Rod During Unit 2 Shutdown Activities.

The inspectors were informed that on September 22, while decreasing reactor power in preparation for the refueling outage, an operator inserted control rod 30-15 from position 48 to position 12. The procedure insertion limit was at position 18. Operators initiated procedure 34AB-C11-004-2S: Mispositioned Control Rod, Revision 1, to correct the error. Reactor engineering assessed the control rod movement error and recommended withdrawing the rod back to the correct location. Reactor engineering personnel and the STA did not identify any thermal limit problem or concern.

The inspectors reviewed the applicable procedures for the licensee identified problem and verified operator actions were correct. The inspectors concluded that, with reactor power at approximately 30% RTP, and control rods being inserted, no core safety limits concerns existed.

The inspectors reviewed procedure 34GO-OPS-065-2S: Control Rod Movement, Revision 14, which was used during the rod movement error. The inspectors noted that procedure step 7.1.1 required the operator to insert a series of control rods from position 48 to position 18. Instead of inserting control rod 30-15 to position 18 the operator inserted the control rod to position 12.

Operations management informed the inspectors that special emphasis was recently directed toward reducing personnel errors especially during reactivity control activities. During the reactor shutdown activities, an additional person had been assigned as a verifier to ensure control rod selection and moves were correctly performed. During this error, the verifier recognized that the control rod being inserted may travel beyond its required position and informed the operator to halt rod movement. However, the operator did not stop his continuous insertion of the control rod in time and the rod continued to travel beyond its required position.

The inspectors reviewed the licensee's immediate corrective actions to prevent similar occurrences. The operator involved was temporarily disqualified from performing evolutions that affect reactivity. This included fuel movement during refueling activities. The rod movement error was discussed with other operating shifts to reemphasize the importance of reactivity control activities and the consequences of personnel errors. The inspectors were informed that operator performance during this problem was not to the level of management's expectations. The inspectors were also informed that disciplinary actions were still under evaluation for the operator and his immediate supervisor. The verifier, even though operations management stated his performance was satisfactory, was counseled.

The inspectors discussed operator performance with respect to reactivity control evolutions with licensee management. The inspectors noted that seven examples of similar problems occurred within the past two years. IR 50-321,366/94-21, 94-24 and 95-08 documented examples where operator errors were made during control rod movements or other activities that affected reactivity.

The inspectors concluded that the individual errors did not present a significant reactor safety limit concern. However, the continued poor performance, represented by a high number of failure to follow procedure or other performance issues, is a concern. The inspectors identified the most recent problem as another example of poor operator performance and inattention to detail during activities that affected reactivity.

Even though management's attention to reduce the number of operator errors during reactivity control activities was increased, operator performance did not improve. This failure to follow procedure during control rod movement is an example of VIO 50-321,366/95-22-01: Operators Failure to Follow Procedure - Multiple Examples.

f. Unit 1 LPCI Inverter Alarm and Trip Problems

The inspectors continued to monitor the spurious tripping problems encountered with the LPCI inverters. These inverters provide UPS for certain key valves associated with LPCI, the Reactor Recirculation system, and RCIC for Unit 1. These problems are documented in IR 50-321,366/95-07.

The inspectors reviewed two DCs initiated by operation personnel on March 7, and 15 for trips of the 1B LPCI inverter. The operators had discovered these trips during a routine panel walkdown. No CR alarm was received for either of these trips. Operations initiated a DC following both trips to identify and document the problem.

The inspectors discussed the trouble shooting and repair activities with engineering personnel. Engineering personnel were responsible for the LPCI inverter problem investigation and to oversee corrective maintenance activities. Early during the investigation engineers determined that the alarm circuit for the LPCI inverter trip was not functioning. They had replaced several components in the circuit in an attempt to correct the alarm problem. Engineering later indicated that the tripping problems have been corrected but an annunciator problem still existed with the Unit 1 1B LPCI inverter. The inspectors noted that engineering personnel were well aware of the inoperable alarm circuit and the extensive maintenance activities performed to correct the problem.

On September 1 and 6, the inspectors questioned control room operators, on two separate shifts, to determine whether or not they were aware of the problem with the LPCI inverter annunciator. The operators questioned were not aware of the problem annunciator or that engineering personnel considered the annunciator to be inoperable.

The inspectors observed that the affected annunciator was not identified as a problem or inoperable annunciator nor was it identified on an annunciator control sheet as specified in procedure 30AC-OPS-009-0S: Control Room Instrumentation, Revision 4. The procedure requires an annunciator control sheet be completed for inoperable or problem alarms. The control sheet was used as an administrative tool to identify, track, and document applicable compensatory actions for alarm deficiencies. None of the above actions were implemented. This failure to follow procedure is identified as an example of VIO 50-321,366/95-22-01: Operators Failure to Follow Procedure - Multiple Examples.

Due to the inspector's questioning on September 6, operations personnel discussed the status of the LPCI Inverter Trouble Annunciator with engineering personnel. As a result, operations declared the annunciator inoperable, compensatory actions were initiated, and the requirements of procedure 30AC-OPS-009-0S, were completed.

The inspectors determined ineffective communications between engineering and operations occurred. Other examples of poor communications between engineering personnel and other departments are documented in IR 50-321,366/95-14 and 95-04. The inspectors discussed this problem with licensee management. The inspectors were informed that management had increased efforts to improve engineering communications with other groups.

One Violation was identified.

3. Maintenance Activities (62703) (61720)

a. 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:

1. MWO 2-95-2833: Troubleshoot and Repair Pump 2A due to Sudden Decrease in Flow

2. MWO 2-95-2939: Troubleshoot and repair RHRSW pump 2B

The inspectors observed that personnel consistently used procedures and exhibited strong communication practices. The inspectors did not identify any specific concerns.

b. Surveillance Observations (61726) (61701)

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 surveillances were reviewed and witnessed in whole or in part:

1. 57SV-C51-004-2S: IRM Instrument Functional Test

2. 57SV-CAL-005-0S: Radiation Monitor Calibration

3. 34SV-F15-001-2S: Refueling Interlocks and Hoist Limit Checks

4. 57SV-SUV-004-2S: Excess Flow Check Valve (EFCV) Operability

5. 42SV-TET-001-2S: Primary Containment Periodic Type B and Type C Leakage Tests

6. 52SV-R43-001-0S: Diesel, Alternator, and Accessories Inspection - EDG 2A

The inspectors observed that personnel consistently used procedures, exhibited strong communication practices, and were proficient with the tasks. No deficiencies were identified.

c. Metal Shavings Discovered on Refuel Floor Overhead Crane

On September 11, during a routine crane PM, maintenance personnel discovered metal shavings on a support beam of the Unit 1 refuel floor overhead crane. The shavings were found on the support beam nearest the auxiliary hoist. The auxiliary hoist is used to hoist and move loads within its weight capacity on the refueling floor including the movement of new fuel bundles and assemblies during new fuel inspection activities.

The licensee's investigation revealed that the metal shavings had come from within the cylindrical drum of the auxiliary hoist. The cabling of the auxiliary hoist is wound around this drum. Each end of the drum has a hole near its outer circumference. A review of the vendor manual by licensee personnel indicated no moving parts with a realistic potential for shaving a metal surface within the drum. The licensee was informed by the vendor that the holes were placed in the ends of the drum to vent smoke, welding gases and pressure during the manufacturing process.

A fiber optic device was used to inspect the internals of the auxiliary hoist drums for both units 1 and 2. Other shavings were found inside the drums, but there was no indications that these shavings were being generated within the drums. The licensee believes the shavings were left over from the fabrication process during hoist manufacturing. To prevent any remaining shavings from coming out the licensee covered the holes with baffle plates.

Metal shavings were not detected anywhere on the refueling floor other than what was found on the overhead cranes. There were no indications that any of the metal shavings had gotten into either spent fuel pool. The metal shavings found on the overhead cranes had no similarity to any debris found in the past on the refueling floor. For these reasons the licensee feels that it is unlikely that any of the shavings posed a past threat of FME on the refuel floor. As a precaution, the licensee stated they plan to inspect the upper tie plates of the new fuel assemblies that have been placed in the spent fuel pool. This inspection will be conducted prior to placing the new fuel into the core.

The inspectors concluded that the licensee reacted in a timely manner to investigate the source of the shavings. The decisions to inspect the Unit 2 overhead crane for similar metal shavings and to cover the holes with baffles to prevent further shavings from escaping was satisfactory.

d. Unit 2 RHRSW Pump Problems

The inspectors noted that all four Unit 2 RHRSW pumps had recently experienced some type of problem. On September 15, the 2A RHRSW pump was in operation for torus cooling. Operations personnel observed pump flow decrease suddenly from about 4,000 gpm to approximately 1,900 gpm. The pump was stopped and declared inoperable.

Upon removal and disassembly of the pump, maintenance personnel found that the pump shaft was worn below procedural tolerance; the line shaft bearings were tight on the shaft; and the impellers had sustained some cavitation damage. Some small debris was also found in the cooling grooves of the rubber bushing.

The inspectors visually examined the debris removed from the pump. None of the debris was large enough to cause a decrease in pump flow. The debris consisted of a small piece of rope, some material that appeared to be plastic, and several small chips of wood. Maintenance also inspected the motor associated with the pump and found no problems.

Maintenance and engineering personnel did not determine a root cause for the decreased flow. Indications of pump degradation were not detected by the trending or predictive maintenance programs. Maintenance engineers stated that the damage was not significant enough to be detected or to degrade pump flow.

Maintenance installed a new pump assembly along with new line shaft bearings. Operations satisfactorily completed the pump operability surveillance September 21, and returned the pump to an operable status.

On September 26, RHRSW pump 2D was in service for Unit 2 shutdown cooling. Operators observed a decrease in pump flow, secured the pump and started RHRSW pump 2B. RHRSW pump 2D was declared inoperable. Contract divers were notified to conduct an underwater inspection of the pump suction.

About 3.5 hours after the 2B RHRSW pump was placed in service, a PEO observed an oil leak on the pump motor. Operations personnel then completed the required valve lineup to crosstie Division 1, RHRSW pumps 2A and 2C, to RHR shutdown cooling. The operators attempted to start the 2C RHRSW pump from the CR and the pump failed to start. The operators then started the 2A RHRSW pump and secured the 2B RHRSW pump. Maintenance was notified to investigate the problem with the RHRSW pump 2C failure to start and the 2B pump motor oil leak.

The inspectors were notified of the problems. The inspectors confirmed that shutdown cooling was in service, and that there was no loss of shutdown cooling.

The inspectors observed electrical maintenance trouble shooting activities for the RHRSW 2C failure to start. The pump motor breaker was removed from its cubicle and connected to a breaker test rig. The breaker was tested several times and failed to close twice during testing. Additional maintenance investigating of the breaker discovered a defective plunger cam in the breaker closing mechanism. The breaker was repaired, post maintenance testing was conducted and the pump was declared operable and placed back in service on September 27.

Maintenance personnel investigated the oil leak on RHRSW pump motor 2B, and concluded that the oil leak was due to a loose cap on the oil vent line. The pump was placed back in service on September 26.

On September 30, operations personnel again observed an oil leak on the 2B RHRSW pump. The pump was removed from service. Maintenance personnel assessed the oil leak and determined the second oil leak was internal to the pump motor. The problem appeared to be with the oil sealing rings or gaskets. They also concluded that the pump should not be placed back in service.

The inspectors discussed the two recent oil leaks with maintenance management. The inspectors were informed that the pump motor was new and that this was the first time the pump motor had been placed in service. Licensee management stated the pump motor would be returned to the vendor for repair.

On September 27, the inspectors were informed that contract divers had completed an inspection of the RHRSW pump 2D. The divers discovered a snake, approximately 5.5 feet in length, had been drawn into the suction of the pump, obstructing pump flow.

The inspectors concluded that operator actions for the RHRSW pump problems were appropriate. A loss of RHR shutdown cooling did not occur and adequate cooling was always available. The inspectors concluded that the recent problems with the RHRSW pumps were isolated events and could not have been predicted. The inspectors also concluded that maintenance and engineering support to operations was timely and post maintenance testing was appropriate.

No violations or deviations were identified.

4. Engineering Activities (37551)

   a. Undervoltage and Load shed of the 1D 600V AC Bus

The inspectors documented in IR 50-321,366/95-18 an electrical load shed involving the 1D 600V AC Bus. The inspectors observed trouble shooting and ongoing work activities and discussed the problem with members of the ERT. Site engineering and maintenance personnel traced the problem to the freight elevator, which was powered from the 600V AC Bus thru a MCC. They determined that a ground was present in the DC electrical system of the elevator. The elevator DC control power system was generated by the use of an auto-transformer and full wave rectification. This type of transformer does not provide any electrical isolation. When the ground occurred a DC circuit was established thru the ground and over to the installed ground in the PT circuit. The DC current flow saturated the PTs and eventually caused the PT fuses to blow. This resulted in the load shedding of the 1D Bus. The power to the elevator was permanently disconnected from the safety related bus and temporarily connected to a non-safety related source, the 2B 600V AC Bus.

Having non-safety related electrical equipment being fed from safety related sources was a concern expressed by the EDSFI in 1991. Had the licensee examined the concern more in depth this occurrence might have been avoided. The inspectors concluded that engineering and maintenance support to operations was very good.

b. Poor Work Practice by Contract Maintenance Personnel.

On September 21, site maintenance personnel began work activities on the 2B RHR/CS area cooler to improve cooling efficiency. Cooler efficiency was approaching the design limit as calculated by procedure 42EN-ENG-026-OS: Service Water Systems Heat Exchanger Testing, Revision 2. When the PSW inlet flange was unbolted, maintenance personnel observed two gaskets when there should have been only one. One of the gaskets had been installed as a solid gasket without a hole cut to match the pipe opening. PSW pressure and flow had opened a hole in this gasket. A similar gasket arrangement was found when maintenance personnel unbolted the outlet flange.

Maintenance personnel removed the gasket material and installed the correct gaskets on the inlet and outlet flanges. A subsequent flow test of the cooler revealed that efficiency and system flow did not improve by any appreciable amount. The cooler was reopened later to clean the tubes as originally planned.

The licensee concluded that even though the gaskets were installed incorrectly; the design flow of the system was not affected. Considerable margin existed between actual PSW flow through the cooler and the design flow requirement. It was routine fouling of the tubes that had decreased the cooler efficiency.

The licensee initiated an ERT to determine when the improperly cut gaskets had been installed. A maintenance history search revealed that the system had last been opened in April 1991. Hydrostatic pressure testing was performed on the PSW piping associated with the cooler as a result of DCRs that had been implemented. To protect the tubes of the cooler from over pressurization during the hydrostatic pressure testing, a blank flange was placed in the inlet and outlet flanges of the cooler. The solid gaskets were installed with the blank flanges. When the blank flanges were removed, the solid gaskets were inadvertently left in the PSW piping system. A normal gasket was added to the PSW piping during restoration for normal use.

The licensee inspected the 2A RHR/CS room cooler PSW flanges. Maintenance was performed on this cooler during the same work activity in 1991. The inspection revealed that the gaskets had also been installed incorrectly on the flanges for this room cooler. PSW flow to the 2A RHR/CS room cooler was also greater than design flow with the incorrect gaskets installed. There was no indications of flow degradation.

Further investigation by the ERT discovered that an incorrectly installed gasket was found in October 1994, on the PSW piping flange to the Unit 1 HPCI room cooler. A maintenance history review revealed that this gasket was installed incorrectly during the same time frame in 1991.

In 1991, shortly after the maintenance work was completed, the licensee conducted a series of room cooler heat exchanger performance tests. The results of the test revealed the cooling capacity of the three coolers were satisfactory. The licensee concluded the three coolers remained operable throughout the time that the gaskets were incorrectly installed. The PSW flow for the Unit 1 HPCI room cooler was less than design but was sufficient to meet the cooling requirements for the room.

The inspectors reviewed applicable procedures, test data and discussed the problem with ERT members and licensee management. The inspectors reviewed procedure 42IT-TET-003-0S: Hydrostatic Pressure Testing of Piping and Components, Revision 1, used for the work performed in 1991. The procedure contained written instructions to prepare the system for test configuration. The inspectors noted no mentioning was made to install a gasket with the blank flange. The inspectors were informed that it was a common work practice to install a gasket with the installation of a blank flange.

A review of the maintenance history revealed contract pipe fitters, under the supervision of PMMS, had performed the cooler maintenance work in 1991.

The inspectors concluded that the installation of a gasket with a blank flange was a reasonable work practice and within the skill of the craft. However, the inspectors concluded that not removing the solid gasket after testing was a poor work practice. Although the inspectors were not able to determine the extent of management involvement or oversight during the maintenance activities, they concluded management attention to contractor activities may have prevented the problem. IRs 50-321,366/94-28, 94-31, and 95-16 document instances where a lack of management involvement and oversight of contractor personnel contributed to equipment failures or problems.

The inspectors concluded that the ERT conducted a thorough and comprehensive investigation. Their root cause determination and assessments were excellent.

c. Modifications

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

DCR	DESCRIPTION
95-02	Security Upgrade
93-66	Shutdown Cooling Low Flow Alarm
94-43	TSI Abatement
94-34	GL 89-10 Valve Modifications

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

No violations or deviations were identified.

5. Plant Support Activities (71750) (65704) (92904)

a. Elimination of Security Guard Post at Entry to Drywell and Refueling Floor.

The licensee did not post security guards at the entry to the drywell and refueling floor for the Unit 2 refueling outage which began September 23. This decision was based upon guidance from the NRC which allowed the promulgation of the provisions of a security rule that becomes effective October 10, 1995. This rule will delete paragraph (d)(8) of Section 73.55 of 10 CFR Part 73 which requires the posting of security guards at these locations.

NRC's Regional and Headquarter security staff concluded that it was acceptable for the licensee to implement the provisions of the rule before its effective date.

b. THe inspectors discussed HP related issues with licensee management. The discussion included program changes to reemphasize the importance of all HP related activities. The inspectors observed HP preparations for the upcoming Unit 2 refueling outage. Some previously closed exits from the RCA were reopened and continuously manned with HP personnel to assist in personnel and equipment monitoring. The inspectors noted that new hand held friskers and tool monitors were placed at the exits from the RCA. The increased sensitivity of the new monitors may reduce the potential for the recurrence of slightly contaminated tools being removed from the RCA. The inspectors observations of frisking activities did not identify any significant problems.

   The inspectors observed training conducted for all plant employees describing the new monitors and their correct use. The inspectors also noted that two HP foreman were conducting full time QC checks for HP activities. Additional improved training for contractor personnel was conducted. The inspectors noted the training was current and more extensive than previously observed training. The training included industry events and contained specific examples for plant Hatch.

   The inspectors concluded that management's attention to HP related issues was very good. Personnel and tool monitoring as well as overall ALARA concerns were among the licensees primary focus.

No Violation or Deviation were identified.

6. Inspection of Open Items (92700) (92901) (92903)

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

a. (Closed) IFI 50-321/92-300-01: Diesel Generator DC Bus not Analyzed Per IN 88-86, Supplement 1. Supplement 1 of the IN identified a previously unidentified potential failure mode of DC distributions. One problem identified was that DC grounds could cause equipment to fail in the energized state instead of the de-energized state necessary to satisfy protection system performance. The Inspector reviewed the licensee's Interoffice Correspondence, dated June 1, 1992, Analysis of Actuation of Equipment Thru the Diesel Battery Ground Detection System. The correspondence referenced IN 88-86 and stated that distribution panel 1R25-S005, 125 VDC Cabinet 1E, was chosen for analysis. The analysis indicated that it was possible that some solid state devices and low current relays could be energized as a result of this type of failure. Additional information indicated that certain components and switchgear breakers would clearly require more current to operate than would be available through the grounding system and would not be a concern. The analysis concluded that although some relays and valves could be energized no unanalyzed conditions would arise. Based on the inspectors review of the analysis, this item is closed.

b. (Closed) IFI 50-321,366/95-08-03: Resolution of the Secondary Containment Negative Pressure and Residual Heat Removal Loop B Flow Oscillations for TSIP Implementation.

This item was originally opened when validation surveillance and testing were being performed for implementation of the new TS. Two specific problems were identified. The first problem dealt with new configurations involving the SBGT systems and secondary containment which did not meet expected results. The second problem dealt with flow fluctuations of the Unit 1B loop of the RHR.

With respect to the first problem, the TRM listed four secondary containment types and surveillance requirements for each type. The secondary containment types consisted of various combinations of Unit 1 and Unit 2 SBGT trains. As a result of actual secondary containment testing, the licensee identified that some secondary containment and SBGT configurations listed in the TS and the TRM would not meet their acceptance requirement. The licensee concluded that two of four combinations that list only the Unit 1 trains needed to be deleted from the TS.

The second problem, flow fluctuations of Unit 1B loop of the RHR, was observed during testing. The new TS surveillances for the Unit 1 RHR system required that both pumps in each train be operated simultaneously. When both pumps in the B loop, pump 1B and 1D were operated, flow fluctuations were observed. The licensee conducted a flow test of the RHR loop and documented the results on MWO 1-95-1362. A total of six transducers were installed, four at the 1B and 1D pump suction and discharge and two at the loop flow orifice inlet and outlet. The results of the test indicated that at 13,000 gpm total flow from both pumps, the upstream and downstream pressure across the flow orifice went out-of-phase. At low flow rates the pressure at these points oscillate up and down but always together. At higher flow rates the pressures fluctuate with no greater frequency or amplitude but out-of-phase. This resulted in erratic differential pressures and thus erratic flow indication in the CR.

The erratic indication was corrected by the installation of snubbers in the sensing lines. The test also indicated oscillations in the pump suctions, the majority being in the 1D pump. This was attributed to internal pump recirculation. Engineering evaluated the system performance and concluded no immediate actions were necessary. The pumps will continue to be monitored for vibration and flow output. The inspector reviewed two graphs which indicated flow at 12,200 gpm and 16,200 gpm. The graphs clearly showed an in phase flow at 12,200 gpm and an out-of-phase flow at 16,200 gpm.

The inspectors concluded that the licensee had adequately addressed both problems. The inspectors observed the secondary containment test, reviewed test data and discussed the pending TS amendments with the licensee. The inspectors also reviewed RHR system test and trending data; observed system inservice performance; and observed the licensee's corrective actions. Based on these actions, this item is closed.

c. IFI 50-366/95-18-01 Additional Review of Unit 2 Manual Scram Due to Condenser Vacuum.

The inspector observed and monitored the licensee's activities involved with the manual scram of Unit 2 which occurred on September 2, 1995. The inspectors initial observations are documented in IR 50-321,366/95-18. The licensee immediately established an ERT to review personnel actions, analyze the event and determine the cause. Part of the analysis included the development of a time line. The inspectors reviewed the time line and discussed with ERT members, their findings, conclusion and recommendations. The inspectors also reviewed procedures, data from chart traces, computer printouts, and graphs. The inspector discussed the scram with operations, maintenance and engineering personnel. The inspectors noted that the problem was discussed with all operating shifts. Members of management were briefed on the results of the ERT investigation.

The ERT concluded that air was induced into the condenser when the flume low level occurred. Control room operators noted the change in differential pressure indication of some condenser water boxes, but took no immediate action. An operations shift change occurred. Operators from the oncoming shift noted a zero pressure differential indication on waterbox 2D and also took no immediate action. Approximately 18 hours after the problem was identified the water boxes were vented. However, the ERT concluded the water boxes may not have been properly vented to void all the air.

From the inspectors review of plant data, procedures and through discussions with ERT members, the inspectors concluded a lack of operator knowledge with respect to air build up in the water boxes contributed to the condition that resulted in a manual scram. The inspectors noted that the chain of events, indications available to monitor system performance, and the thermodynamics of the water boxes contributed to the complexity of the problem. The operators did not take timely actions to vent the water boxes. The loss of vacuum resulted from sections of the condenser becoming air bound and thereby losing capability of condensing steam. This resulted in the 2A condenser becoming thermally over loaded.

ERT recommendations and procedure enhancements were being evaluated by the licensee for short and long term corrective actions. The recommendations also included items for operator training improvements. Based on the inspectors reviews, observation and discussions, and licensee actions, this item is closed.

7. Exit Interview

The inspection scope and findings were summarized on October 10, 1995, 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
VIO 50-321,366/95-22-01	Open	Operators Failure to Follow Procedure - Multiple Examples (paragraph 2.e, 2.f).
IFI 50-321/92-300-01	Closed	Diesel Generator DC Bus not Analyzed Per IN 88-86, Supplement 1 (paragraph 6.a).
IFI 50-321,366/95-08-03	Closed	Resolution of the Secondary Containment Negative Pressure and Residual Heat Removal Loop B Flow Oscillations for TSIP Implementation (paragraph 6.b).
IFI 50-366/95-18-01	Closed	Additional Review of Unit 2 Manual Scram Due to Condenser Vacuum (paragraph 6.c).

8. Acronyms and Abbreviations

AC - Alternating Current
ALARA- As low as reasonably achievable
CFR - Code of Federal Regulations
CR - Control Room
CS - Core Spray
DC - Deficiency Card, Direct Current
DCR - Design Change Request
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EDSFI- Electrical Distribution System Functional Inspection
ERT - Event Review Team
FME - Foreign Material Exclusion
FW - Feedwater
GE - General Electric Company
gpm - Gallons per minute
HP - Health Physics
HPCI - High Pressure Coolant Injection
I&C - Instrumentation and Controls
IR - Inspection Report
IRM - Intermediate Range Monitoring System
LER - Licensee Event Report
LPCI - Low Pressure Coolant Injection

MCC - Motor Control Center
MWO - Maintenance Work Order
NRC - Nuclear Regulatory Commission
OJT - On Job Training
NRR - Nuclear Reactor Regulation
PEO - Plant Equipment Operator
PMMS - Plant Modification and Maintenance Support
PT - Potential Transformer
PSW - Plant Service Water System
QC - Quality Control
RCA - Radiological Control Area
RCIC - Reactor Core Isolation Cooling
RHR - Residual Heat Removal
RHRSW- Residual Heat Removal Service Water
RTP - Rated Thermal Power
SBGT - Standby Gas Treatment
SPDS - Safety Parameter Display System
SS - Shift Supervisor
STA - Shift Technical Advisor
TRM - Technical Requirement Manual
TS - Technical Specifications
TSI - Thermal Science Incorporated
TSIP - Technical Specification Improvement Program
UPS - Uninterruptible Power Supply
VDC - Volts Direct Current
VIO - Violation