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

Report Nos.: 50-321/94-08 and 50-366/94-08

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

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

Facility Name: Hatch Nuclear Plant

Inspection Conducted: March 13, 1994 - April 16, 1994

Inspectors:	D. A. Seymour for Leonard D. Wert, Jr., Sr. Resident Inspector	5.12.94 Date Signed
	D. A. Seymour for Edward F. Christnot, Resident Inspector	5.12.94 Date Signed
	D. A. Seymour for Bob L. Holbrook, Resident Inspector	5.12.94 Date Signed
Approved by:	Pierce H. Skinner, Chief, Project Section 3B Division of Reactor Projects	5/12/94 Date Signed

SUMMARY

Scope: This routine resident inspection involved inspection onsite in the areas of operations including: refueling floor activities and review of a Unit 1 scram; surveillance testing and review of an inadvertent engineered safeguards actuation; maintenance activities; modifications; Unit 2 fuel inspection; and review of open items. A review of the licensee's overtime policy and controls was conducted.

Additionally, the inspection included observation of a Safety Review Board (SRB) meeting and review of engineering and technical support resources, both of which were performed during visits to the licensee's corporate office.

Results: One violation was identified.

The violation addressed three examples of personnel errors for failure to follow procedures during fuel movement activities. The licensee identified that fuel bundle locations were not as specified in the procedures. While personnel errors were involved, it was considered significant that the required double verification failed to correct the errors. (Violation 50-366/94-08-01: Insufficient Verification of Bundle Location During Fuel Movement, paragraph 2c). The inspectors observed numerous refueling floor activities and

REPORT DETAILS

1. Persons Contacted

Licensee Employees

D. Bennett, Chemistry Superintendent
S. Bethay, Hatch Licensing Manager, Southern Nuclear
*J. Betsill, Unit 2 Operations Superintendent
S. Brunsen, Engineer, Nuclear Safety and Compliance
*D. Carroll, Plant Equipment Operator
C. Coggin, Training and Emergency Preparedness Manager
*S. Curtis, Operations Support Superintendent
D. Davis, Plant Administration Manager
B. Duvall, Plant Engineering Supervisor
*P. Fornel, Maintenance Manager
*O. Fraser, Safety Audit and Engineering Review Supervisor
*G. Goode, Engineering Support Manager
L. Gooden, Shift Supervisor
*M. Googe, Outages and Planning Manager
S. Grantham, Acting Training and Emergency Preparedness Supervisor
*J. Hammonds, Regulatory Compliance Supervisor
*E. Hopkins, Operations Shift Support Supervisor
*W. Kirkley, Health Physics and Chemistry Manager
L. McDaniel, Acting Manager, Plant Administration
*B. McGinn, Security Operations Supervisor - Nuclear
T. Metzler, Acting Manager Nuclear Safety and Compliance
*C. Moore, Assistant General Manager - Operations
J. Payne, Senior Engineer
*C. Ponder, Financial Services Supervisor
*D. Read, Assistant General Manager - Plant Support
*R. Reddick, Emergency Preparedness Coordinator
*K. Robuck, Manager, Modifications and Maintenance Support
*H. Sumner, General Manager - Nuclear Plant
J. Thompson, Nuclear Security Manager
*S. Tipps, Nuclear Safety and Compliance Manager
*P. Wells, Operations Manager

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

NRC Inspectors

*L. Wert, Senior Resident Inspector
*E. Christnot, Resident Inspector
*B. Holbrook, Resident Inspector
D. Seymour, Project Engineer

* Attended exit interview

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

2. Plant Operations (71707) (93702) (60710) (60705)

a. Operations Status and Observations

Unit 1 began the report period at 100 percent RTP. At 8:58 pm on March 25, an inadvertent ESF actuation occurred during I&C testing. Power was reduced to about 600 MWe. Paragraph 3.b of this report discusses that event. Power was returned to 100 percent RTP at 2:10 a.m. on March 26, and remained at that level until 1:01 a.m. on March 29, when a reactor scram occurred. The scram resulted due to a problem in the main generator exciter and is discussed in paragraph 2.b of this report. After the exciter rotor was changed out with the rotor from Hatch Unit 2, Unit 1 was restarted and 100 percent RTP was reached on April 2. The unit continued operation at that level through the remainder of the report period.

Unit 2 began the report period operating at 70 percent RTP. On March 15, a reactor shutdown was commenced for a scheduled refueling outage. At 1:49 a.m. on March 16, the reactor was manually scrammed in accordance with the shutdown procedure. At 2:54 a.m. on March 17, cold shutdown was attained. On March 17, 1994, at approximately 11:31 a.m., Unit 2 experienced a loss of shutdown cooling flow. The event occurred while an engineer was obtaining data (from inside of a control room panel) for a planned modification. Details of the event are documented in IR 50-321,366/94-09. Fuel was completely offloaded from the reactor on March 25. The refueling outage was still in progress at the end of the report period.

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

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

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

Reactor Building	Diesel Generator Building
Fire Pump Building	Intake Structure
Station Yard Zone	Turbine Building
Refuel Floor	Unit 2 Torus (proper)

On March 16, 1994, the inspector observed and reviewed the licensee's activities in the shutting down of Unit 2 in preparation for refueling outage activities. Among the activities observed were unit power reduction and cooling down and depressurization to initiate shutdown cooling. The inspector noted that the operators used the RCIC system to assist in the depressurization. The inspector observed the performance of various plant evolutions and noted no deficiencies.

Equipment clearances, initiated for the Unit 2 outage, were reviewed for proper preparation and execution. Applicable circuit breakers, switches, and valves were walked down to verify proper plant configuration. Tag labeling was verified to be legible and accurate. Among the clearances reviewed were:

2-94-479	EDG 2A
2-94-489	PSW Pump 2A
2-94-375	Unit 2 Station Service Battery 2A
2-94-380	PSW to turbine building DIV I and DIV II valves 2P41-F316A and 2P41-F316B.

The inspectors observed refueling floor activities frequently throughout the report period. Several of these observations were conducted on evening and night shifts. The inspectors monitored activities on several occasions from the refueling bridge to verify activities were being conducted in accordance with procedures. The inspectors observed that proper bundle identification, and locations were verified. Also, it was observed that the operators were taking the necessary actions to verify that fuel bundles were properly attached to the fuel grapple prior to bundle being lifted and moved. As discussed in IR 50-321,366/94-05, the inspectors continued to note that refueling floor activities were strongly supervised. Paragraph 2.c of this report describes several issues which involved exceptions to these overall observations.

During routine tours of the plant several minor deficiencies were noted involving material not properly stored or disposed of. The inspectors identified that a large sheet of plastic was partially blocking the flowpath for air into the intake structure. The inspectors found a piece of lightweight foam rubber immediately adjacent to and under the Unit 2 refueling floor SBGT suction piping. The material could have blocked one of the two pipes if SBGT had been initiated. In both cases the material was immediately removed. The inspectors concluded that neither of these issues by themselves would have prevented a safety system from performing its function, but more attention to detail should have resulted in the conditions being corrected earlier.

b. Unit 1 Automatic Scram

At 1:01 a.m. on March 29, 1994, Unit 1 automatically scrammed from 100 percent RTP. The scram was initiated when the turbine tripped due to the loss of generator excitation. The turbine tripped, reactor recirculating pumps tripped, and the SRVs opened to maintain reactor pressure. The lowest indicated reactor water level was +14 inches. The reactor scram setpoint is approximately +12 inches. ECCS was not initiated. However, there was a 1/2 group II isolation signal generated. Emergency Procedure 31EO-EOP-010-1S: Reactor Pressure High, was entered and was exited when reactor pressure stabilized. Both reactor recirculating pumps were restarted to provide forced circulation. Operations entered the normal shutdown procedure and maintained the Unit in a hot shutdown condition. An ERT was initiated to investigate the scram. An investigation was initiated regarding the loss of generator excitation. The investigation revealed that the exciter slip rings showed signs of overheating and the exciter shaft was significantly scarred.

Following the event, the inspectors conducted a panel walkdown in the CR and verified that systems were in operation and aligned as required. A review of the operator logs revealed that system restoration was timely and actions had been completed as required by the Emergency and Normal operating procedures. The inspectors concluded that the operator actions following the scram had been both timely and correct.

The inspectors viewed the exciter slip rings and exciter shaft and observed the damage. Following discussions with plant management, it was learned that the recovery plan was to replace the damaged exciter rotor with the Unit 2 equipment. GE reviewed the equipment and components and concurred with the Unit 2 exchange.

At 6:08 p.m. on March 31, the reactor was brought critical following completion of the maintenance activities. 100 percent RTP was achieved at approximately 6:25 a.m. on April 2.

Several licensee identified equipment problems occurred during the restart activities:

Water in the RFPT Lube Oil Reservoir;

Water entered the "A" RFPT lube oil reservoir. This is a reoccurring problem. The RFPTs were isolated in preparation to break condenser vacuum. The pump suction valves were isolated as well as the seal water isolation valves. The problem apparently resulted due to the RFPT suction valves not being securely closed when the RFPTs were isolated. The suction valves were later manually closed more tightly. The oil reservoir was centrifuged to separate the water and clean the oil.

Difficulty Rolling the "A" RFPT;

When attempting to roll the "A" RFPT during startup, turbine speed would not increase. I&C determined the MGU Low Setpoint was out of adjustment. Adjustments were made and startup was continued. Also, a MWO was issued to conduct further investigation on the RFPT linkage.

Also, during startup of the"B" RFPT it was observed that the tripped annunciator did not always alarm when the RFPT was tripped. A DC was initiated to determine why the alarm would not actuate for each trip. I&C investigation determined that the problem was with a pressure switch. To perform repairs would require the oil system to be removed from service. The SOS decided that the repairs should be made later during an outage. The inspectors observed that operations had labeled the annunciator window with an annunciator tracking number. A discussion was held with operations management concerning the fact that the alarm might not actuate to alert CR operators on shift that the RFPT had tripped. Operations management determined that other adequate indications were available to alert the operators and additional compensatory actions would not be required.

Difficulties Establishing Turbine Chest Warming;

When attempting to establish turbine chest warming during startup, the number 2 stop valve poppet would not open. The electrical circuits were verified correct, and the number 2 stop valve servo was inspected. The servo strainer was replaced and warming was commenced. Later during chest warming and increasing potentiometer position, stop valve 1, 3, and 4 opened. I&C investigation identified that the logic cards seemed to be the problem. This resulted in pulling and reseating 2 relay boards, which corrected the problem.

Broken CR Handswitch

While attempting to place the "A" EHC pump in service, the circuit breaker would not close. Investigation determined that the CR handswitch contained broken contacts. The handswitch was replaced with a Unit 2 handswitch. There was no available hand switches in the warehouse. This corrected the problem.

Difficulties Warming the "A" Reactor Recirculation Loop

While maintaining the reactor in hot shutdown, SDC was placed in service. The reactor recirculation system was removed from service, in accordance with procedures, prior to starting SDC. During reactor startup the "A" recirculation loop was started and placed into service. Difficulty was encountered while attempting to warm the "B" loop. TS section 3.6.D requires that the temperature between the running and idle loop be within 50 degrees F prior to startup of the idle loop. The system operating procedure contained a caution concerning the heatup and cooldown limits and provided guidance to warm the idle loop. This guidance included opening the idle pump discharge valve and/or if necessary, increasing the speed of the running pump to obtain better circulation within the idle loop. The speed on the running pump was increased and the discharge valve on the idle pump was cycled open and closed two times to obtain warming, which resulted in an approximate 40 to 50 degrees F increase. On the third open and close cycle the temperature increased 80 degrees F. This resulted in the 100 degree F per hour heatup procedural limit being exceeded by 10 degrees F. The idle loop was started with no additional problems. The inspector reviewed an analysis performed by GE that stated that the fatigue impact on the recirculation pump and piping of a 180 degree F heatup step change is insignificant. Therefore the inspector concluded that the 110 degree per hour heatup over a long period of time was not safety significant. The licensee is assessing the procedural guidance to prevent further heatup limit requirement violations.

EHC Leak

The PEO reported a small EHC oil leak on the 1 "B" EHC pump compensator lock nut. A DC was initiated and maintenance repaired the leak. As discussed in previous IRs, EHC system leaks have previously caused problems at Hatch.

These equipment problems challenged the plant staff during recovery to power operations. The inspectors noted that some of the problems were additional examples of recognized equipment issues. Several of the problems were equipment failures which would not be expected to be prevented by preventive maintenance.

c. Personnel Error During Fuel Loading

At approximately 2:30 pm on April 15, 1994, it was determined that an error had been made during a previous movement of fuel. Fuel was being reloaded into the Unit 2 reactor vessel from the Unit 2 SFP. In accordance with move sheet step 151 of 42FH-ERP-014-OS: Fuel Movement, the refueling bridge was positioned to obtain a fuel bundle from location 10B08 (rack number 10, grid location B-08) in the SFP. Personnel on the bridge noted that a single blade guide was located in that position instead of a fuel bundle. Fuel movement was immediately stopped and the appropriate personnel were informed of the problem.

An inspector had just entered the refueling floor area to monitor fuel movement activities at the time the problem was identified. The inspector observed the immediate recovery and corrective actions. The licensee determined that an error had occurred at approximately 6:45 a.m. that morning. Move sheet step 116 of 42FH-ERP-014-OS required that a bundle be pulled out of SFP location 10B09 and placed into core location 19-36. Visual inspection of the fuel bundle at that core location identified that the bundle from SFP location 10B08 had been moved instead of the bundle at SFP location 10B09.

The status of the involved SFP racks and the core were verified. It was confirmed that all other rack and core locations expected to be empty were actually vacant and that fuel bundles were present in the expected locations. The inspector observed most of these checks from the refueling bridge. The inspector also noted that procedural requirements were followed regarding the necessary corrective changes to fuel movement procedures. Discussions with reactor engineers indicated that both fuel bundles involved (the one moved in error and the one that should have been moved), had already been used for three operating cycles. The reactivity of the bundles was low and approximately equivalent, so no unplanned reduction in shutdown margin had resulted.

The SRO on the refueling bridge when the error was identified was also the SRO on the bridge at the time the error had occurred. The inspector's discussions with the involved personnel indicated that the error may have occurred as a result of an earlier problem. The SRO recalled that, at about the time that the error apparently occurred, the operator had raised the mast without a fuel bundle grappled and that he had immediately corrected that problem. However, the SRO did not recall reverifying the SFP location when a fuel bundle was subsequently removed from the SFP. The inspector noted that Procedure 34FH-OPS-001-0S: Fuel Movement Operation, steps 7.1.9 and 7.1.10 require that the double hook shut light be verified and the mast rotated manually before the bundle is lifted. The inspector discussed, with the SRO and management, that more complete actions in response to this "initial" personnel error would have been appropriate. On numerous occasions during observation of fuel movements, the inspectors have specifically verified that personnel were rotating the mast prior to lifting bundles.

The individuals that were on the refueling bridge at the time of the error (SRO, RO, and a reactor engineer) were temporarily disqualified for fuel movement activities. Fuel movement was restored after additional corrective actions were completed by management. A memorandum was included in the Operations Manager night orders, which explained the problem and established enhanced confirmation expectations during fuel movement. During subsequent observations of core loading activities, the inspectors noted that these measures were being implemented. After verification that the status of the pertinent SFP racks and the core was completed satisfactorily, revised fuel movement sheets were used to restore the fuel loading to the planned arrangement.

Steps 7.2.1.2.3.1, 7.2.1.2.5.1, and 7.2.1.2.5.2 of Procedure 42FH-ERP-014-0S require that the SFP location, core location, and orientation be checked and verified by the reactor engineer on the bridge. An additional verification is required by an SRO/RO after the bundle is in its final position. The inspectors concluded that personnel error and insufficient attention to detail by several individuals had caused a bundle to be loaded into a core location different than the location prescribed on the movement sheets. Personnel had promptly reported the problem upon identification and appropriate corrective actions were completed. The inspectors concluded that the safety significance of the error was minimal. It was also noted that the licensee's procedural controls required that a full core verification be performed and independently reviewed after fuel loading is completed.

As discussed in paragraph 2a of this report and in IR 50-321,366/94-05, the inspectors have noted good procedural compliance, supervisory involvement and attention to detail during their observations of fuel movement activities this outage.

At approximately 3:00 a.m. on March 30, a different fuel loading error had been made. An incorrect fuel bundle had been moved from the spent fuel pool to the fuel prep machine. Fuel bundle LYX 105 in fuel pool location 9H09 was placed into the fuel prep machine. The correct bundle was LYX 099 in fuel pool location 10H09. The fuel bundle that was moved was one rack away from where the correct bundle was located. The technicians performing the inspections of fuel in the fuel prep machines identified the incorrect bundle. The inspectors reviewed the procedures associated with fuel movement and verified that the proper corrective actions had been performed. Engineering was notified and move sheets were prepared to relocate the fuel bundle back to the correct location. The inspectors also reviewed the move sheets and documentation associated with the relocation of the fuel. The inspectors concluded that this was another example of in which personnel error and improper verification resulted in bundles being moved to different locations than those specified in the procedures.

While it is recognized that personnel errors can occur during fuel movement activities, the inspectors' primary concern was that the double verification process for fuel bundle identification and location was not properly performed. These examples are identified as Violation 50-366/94-08-01: Insufficient Verification of Bundle Location During Fuel Movement.

One violation was identified.

3. Surveillance Testing (61726)

a. Surveillance Observations

Surveillance tests were reviewed by the inspectors to verify procedural and performance adequacy. The completed tests reviewed were examined for necessary test prerequisites, instructions, acceptance criteria, technical content, authorization to begin work, data collection, independent verification where required, handling of deficiencies noted, and review of completed work. The tests witnessed, in whole or in part, were inspected to determine that approved procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and systems restoration was completed.

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

1. 42SV-R42-003-0S: Battery Inspection (Attachment 2)
2. 42SV-R42-008-0S: Battery Capacity Test (Performance Test)
3. 42SV-R43-001-0S: Diesel Alternator and Accessories Inspection
4. 34SV-R43-004-2S: Diesel Generator 2A Semi-Annual 24 Hour Run and Hot Restart Test
5. 34SV-SUV-E41-002-1S: HPCI Pump Operability
6. 42SV-R42-008-0S: Battery Capacity Test Performance Test
7. 42SV-R42-003-0S: Battery Inspection
8. 52SV-R43-001-0S: Diesel, Alternator and Accessories Inspections.
9. 42SV-R42-006-0S: Battery Load Discharge Test (Service Test)
10. 34SV-R43-006-2S: EDG 2C Semi-Annual, 24 Hour Run and Hot Restart Test
11. 52SV-R42-001-1S: Battery Pilot Cell Surveillance

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

b. Unit 1 ESF Actuation

At 8:53 p.m. on March 25, 1994, Unit 1 was operating at 100 percent RTP. I&C technicians were performing Procedure 57SV-SUV-012-1A: ATTS Panel 1H11-P926 Channel Functional Test and Calibration. A Unit 1 ESF actuation occurred. The actuation was initiated when a false low level LOCA signal was generated. All ECCS equipment responded as expected. EDGs 1A, 1B, 1C, Core Spray 1A, and 1B started. Control room ventilation aligned to the pressurization mode and the turbine building PSW isolated as expected. Step 7.28.5.4 of the procedure required the technician to connect a VOMS (ohms) meter from link BB-20 to link BB-21 in panel 1H11-P627. However, the technician connected the instrument from link BB-21 to link BB-22, and when additional procedure steps were performed, the actuation was initiated. Operators entered the abnormal operating procedure for the loss of PSW when the turbine building PSW valves (1P41-F310 A-D) closed. The operators bypassed the isolation signal but were unable to open the F310 A and B valves from the CR handswitch due to a high differential pressure. Operators were dispatched to open the valves locally. Once the valves were slightly opened from their closed seat (manually) the motor continued to open the valves and PSW was restored to the turbine building. The operators, due to plant equipment temperature increases, decreased reactor power to approximately 70 percent by decreasing reactor recirculation pump speed.

While restoring the ECCS systems to normal standby, the 1A EDG received a battery charger malfunction alarm and a battery ground alarm. The EDG was declared inoperable and an LCO was entered. Procedure 34AB-R42-001-0S: Location of Grounds, was entered. The ground was located on 1R25-S004 breaker 10. An investigation later determined the ground to be a wire on the 1A EDG speed switch. The electricians repaired the wire, the ground was cleared and the EDG operability surveillance was satisfactorily performed. All systems were returned to normal configuration; power was been restored to 100 percent at 2:10 a.m. March 26.

An inspector responded to the site to investigate the event. Part of the recovery actions were observed from the CR. A review of the procedures indicated that required actions were performed. A walkdown of the CR panels indicated all systems had been returned to normal with the exception of the 1A EDG. The operations SOS and SS were providing adequate oversight. The inspector reviewed some of the SPDS tape data with the ERT members to verify proper system response. The inspector reviewed the surveillance procedure that was being performed by the I&C technician. It was noted that there were some inconsistencies within the procedure. The steps that required the technician to place the meter on the required links did not have areas to initial indicating that the steps were performed. Other steps in the same procedure had areas to initial indicating similar steps were completed. However, the inspector concluded that initializing the step most likely would not have prevented the meter from being placed on the incorrect link.

The inspector reviewed the Generic Writers Guide, WG-1, and the Surveillance Procedure Writers Guide, WG-29, for additional information. WG-29 stated that generally, each action will be initialed by the individual performing the step. However, the procedure also stated that other methods may be both acceptable and desirable for certain procedures and that the Writer and Department Manager, in consultation with The Procedure Review Group, should determine exactly which method is most appropriate and user friendly in a particular procedure. The surveillance procedure did require final verification of system restoration as suggested by the Writers Guide and as required by regulations. The inspector discussed these issues with I&C management who stated the procedure methodology was under review.

Following discussions with licensee representatives, the inspector noted that the individual was disciplined according to the licensee's Positive Discipline Program. The individual's certification was suspended and they will be required to undergo additional training. A demonstration, to department supervision, of proficiency necessary to conduct work in CR panels, will be required. Department management conducted a briefing of the incident for the day shift personnel. The briefing was video taped and will be viewed by the remaining shifts. Also, it was explained to the inspector that if the meter is correctly used as a high impedance device, the connections would not act as a jumper. This technique will also be explained and demonstrated to the I&C personnel. Had the instrument been used in a high impedance manner the actuation most likely would not have occurred. The inspector noted that the recent performance of the I&C department was generally excellent. The personnel are very safety conscious and proficient in their work activities. This event is the first incident of this type in approximately 15 months. The inspector concluded this incident is an isolated case of personnel error and that the licensee initiated appropriate actions.

No violations or deviations were identified.

4. Maintenance Activities (62703)

a. Maintenance Observations

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

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

1. MWO 2-94-0704: ECCS System Strainer Inspection
2. MWO 2-94-096: Inspect Air Start Distributer on the 2A EDG
3. MWO 2-94-097: Inspect Air Start Distributer on the 1B EDG
4. MWO 2-94-098: Inspect Air Start Distributer on the 2C EDG
5. MWO 2-93-3877: Calibrate 2A EDG Cooling System Expansion Tank Level Switch

6. MWO 2-94-532 & MWO 2-94-544: Replace Type CR-120 Relays Indicating Excessive Temperature (213 to 223 F)

7. MWO 2-94-2179: 18 Months PM on EDG 1B

The MWOs involved with the air start distributors were initiated due to a 10 CFR Part 21 item. The inspector's reviews indicated that the licensee completed appropriate actions to address the concern.

On June 15, 1993, Unit 1 scrammed when an I&C technician touched a reactor water level variable leg instrument isolation valve to shut it. IR 50-321,366/93-11 contained details of this issue. One of the recommendations made by the ERT that investigated the scram was to inspect other critical high potential instrument nuts for tightness. During the Unit 2 outage, the licensee conducted an inspection of approximately 115 Unit 2 instruments to verify tightness of the instrument nuts. The inspectors reviewed the licensees activities concerning this issue. The inspectors reviewed the MWO, work packages, P&IDs, and the completed investigation results. Discussions were conducted with I&C personnel responsible for the inspection. There were no discrepancies identified.

b. Drywell Head Dropped About 8 Inches Due to Collapse of Cribbing

On April 15, 1994, at 9:30 a.m., one side of the Hatch Unit 2 DW head fell about 10 inches to the floor. One of the three "legs" of wood cribbing used to support the head had collapsed suddenly. No personnel were working on the head at the time and no injuries occurred. The DW head weighs 45 tons. Reloading of fuel into the Unit 2 reactor vessel was in progress at the time and was not effected. The senior resident inspector was in the CR and responded to the refueling floor.

The head was lifted off of the floor and a visual inspection was conducted. There appears to be a very small amount of "roughness" on the edge of the flange where it contacted the floor which will be easily smoothed out. The floor was not damaged. The wood dunnage was crushed. Apparently, the wood and a coil of air hose which had been under the flange helped to cushion the fall. The head rests on the three wood "blocks" on three "leg" support pieces which protrude a small amount out past the flange. The wood was replaced and the head was set back down on the blocks.

It was noted that the blocks are covered for contamination control, preventing a detailed inspection of the condition of the wood. The inspector questioned the condition of the crushed wood and was informed that it contained significant moisture.

The inspector observed the initial recovery actions and reviewed the applicable procedures. The pre-move checklist for heavy loads movement was utilized. The inspector concluded that the head had been stored in accordance with procedures. Discussions with GE personnel on the refueling floor indicated that the licensee's method of support of the head is similar to those used by other licensees.

The inspectors concluded that the safety significance of this incident was small, but that serious personnel injury could have occurred. Personnel were working in the reactor vessel head area which is only a few feet away from the DW head. Information indicated that the routine DW head flange checks had been performed several days prior to this incident.

c. ECCS Strainer Inspection

On May 11, 1994, the NRC issued NRC Bulletin NO. 93-02: Debris Plugging of Emergency Core Cooling Suction Strainers. The licensee response to this bulletin was transmitted to the NRC on May 25, 1993. IR 50-321,366/93-08 contained details of the response verification. During this refueling outage, the inspectors observed part of the licensees activities to inspect the ECCS strainers inside the suppression pool. The inspectors reviewed the MWO work package and procedures and observed the actual inspection of 3 different ECCS suction strainers. The inspection was conducted by lowering a portable camera into the suppression pool water and monitoring the camera image on a screen. It was noted that a site QC inspector and GE engineers conducted the inspection. Other than a few minor technical problems dealing with the camera equipment, the inspection went very well. The inspectors observed no significant blockage problems on the 3 strainers. Some isolated small areas of blockage were noted. The licensee's final report indicated that the largest cumulative amount of blockage observed was less that 1 square inch. The inspectors will tour the drywell prior to restart to verify that no significant loose insulation material problems exist.

d. EDG Dowel Pin Issue

The 1B EDG was removed from service for extensive outage maintenance at about 6:30 p.m. on April 7, 1994. This was a seven-day LCO on Unit 1, which was at 100 percent RTP. Since Unit 2 does not have fuel in the vessel, there is no EDG operability required.

On April 11, during the maintenance efforts on the 1B EDG, the licensee identified a problem associated with several dowel pins located on the "V-blocks" between the rotor windings (salient poles) of the generator. Several of the dowels have apparently become loose and have moved out of their expected position. The licensee requested vendor assistance and a representative reported onsite late that night.

The inspectors followed the issue closely. Visual inspection of the 1B EDG confirmed that a number of the dowels were protruding from the top of the V-blocks. Some dowels extend as far as 1/2 inch past the surface while others just barely protrude. Additionally, it was noted that at least one dowel had moved "downward" (towards the rotor). It was difficult to see the blocks, especially those located toward the center and on the underside of the rotor.

A cursory examination by the inspector of the four other EDGs indicated that the problem, if it did exist on those EDGs, was not as severe as on the 1B. Only a small percentage of the V-blocks on the other EDGs could be examined because of interferences. It was noted that the Unit 2 EDGs had only two V-blocks between the windings, not three as the Unit 1 EDGs have. Discussions with the licensee indicate that the dowels may not have been closely examined in the past. The inspectors discussions with the vendor representative indicated that he was not sure of the configuration and had not encountered this issue before.

The inspectors questioned the licensee regarding potential effects/consequences of a dowel coming completely out while a EDG was running. The licensee indicated that if the pins were to be ejected during EDG operation, the soft material of the pins (wood) would result in them being destroyed by contact with the other surfaces in the generator. The primary concern was that, if the pins were ejected, the V-block pieces may rotate and rub against the wiring on the windings.

The licensee evaluated several alternatives to address the issue. Due to the licensees initial efforts to investigate, inspect, and repair the EDG it was uncertain as to the amount of time required to complete these actions. Due to the uncertainty, the licensee contacted the inspectors, Region II and NRR personnel, and discussed a potential request for Regional Enforcement Discretion regarding Unit 1 TS 3.9.B.2. However, the licensee decided that appropriate actions would be to thoroughly inspect the EDGs and then glue shifted dowel pins back into their proper position. The licensee developed a Regional Enforcement Discretion request but due to the licensee's timely investigation and maintenance actions, the request was not needed. Following the maintenance activities the EDG was run to verify operability and no additional discrepancies were noted. The licensee inspected the remainder of the EDGs. No maintenance work was required to be performed on the 2A, 2C, and 1C EDG. Several dowel pins were glued on the 1A EDG.

The inspectors concluded that the licensee's corrective actions had been appropriate and timely.

No violations or deviations were identified.

5. Licensee Use of Overtime (71707)

The inspector performed a review of the licensee's overtime policy and implementation as directed by regional management. Section 6.0 of the TS and Procedure 30AC-OPS-003-0S: Plant Operations, established the policy, requirements, and responsibilities for the use of overtime. The procedure quotes sections of the TS and designates the assistant general managers as the approving authority for any deviations that exceed the TS limitations. The inspector reviewed overtime records for many of the departments and noted that during non-outage periods, overtime is kept at a minimum. As expected, when the units have been shutdown, overtime increases. During all plant conditions, the licensee applies identical controls to overtime.

As a result of the reviews, the inspector concluded that overtime which exceeded the TS limits was not routine and was requested and approved in accordance with the administrative control procedure. However, one discrepancy was noted. During a recent outage, two GE contract workers exceeded TS limits without proper management approval. Information indicated that these workers were not involved in safety related activities. NCV 50-321,366/92-32-02: Unauthorized Deviations of Overtime Limits by HP Personnel, addressed two instances in which personnel had exceeded hourly overtime limits without prior approval. Those examples had been identified by the licensee's overtime monitoring system. The inspector concluded that the usage of overtime continues to be adequately controlled by the licensee.

No violations or deviations were identified.

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

a. Observation and Reviews of Modifications

The inspectors continued to review and observe many of the ongoing modification activities. The DCR packages for the following modifications were reviewed:

DCR 88-106	Remove MSIV Leakage Control System.
DCR 90-130	Replace RHRSW HX Control Valves 2E11-F068 A & B.
DCR 91-144	Seismic Anchorage for EDG MCC.
DCR 91-145	Seismic Anchorage for EDG MCC.
DCR 92-137	RHRSW Air Release Valves
DCR 92-054	Main Steam Line Hi Rad Monitor Trip
DCR 92-164	Relocate HPCI Injection to Feedwater Valve 2E41-F006.
DCR 93-03	Replace Shroud Access Hole Cover With Bolted Design.
DCR 93-09	RPS MG Set Time Delay.
DCR 93-22	Install New Electrical Penetration.
DCR 93-31	Alternate Decay Heat Removal.
DCR 93-62	Replace Unit 2 Station Service Battery.

The inspectors observed specific activities associated with various DCRs. Observations included; initial installation activities of some DCRs, activities performed during the 40 percent to 60 percent modification complete milestones on other DCRs, and the final installation activities and post modification testing on other DCRs. The assessment of DCR 92-54, Removal of Main Steam High Radiation Scram, consisted solely of reviewing documentation. The assessment of DCR 93-62, Station Service Battery Replacement, consisted of all areas of activities from initial DCR work to final post modification testing. Specific areas of detailed observation included:

DCR 93-62	The removal of old cells, installation and handling practices of the new cells, resistance testing of the battery cell interconnections, and post modification testing including the TS required performance test.
DCR 93-137	The removal of two valves, installation of hangers and four valves.
DCR 93-144	Installation of additional welded seismic supports to EDGs 2A and 2C MCCs.
DCR 93-09	Refuel floor activities involving the cutting out of the welded access hole covers and the installation of the new bolted hole covers. Part of the observations included the full scale makeup installed in the PM&MS building.
DCR 93-22	Observation of the type of CONAX penetration to be installed, initial installation activities at the spare drywell nozzle and the post installation indications on SRM and IRM channels.
DCR 93-31	The inspector continued to observe the final installation activities, such as instrument tubing and temperature indicators. The inspector also observed the performance test and periodically observed the alternate FPC system in actual operation.

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

b. New Decay Heat Removal System Test

Prior to the March 1993 Unit 1 refueling outage, the licensee had completed DCR 1H93-001, which installed permanent support equipment to interface with a temporary auxiliary fuel pool cooling system. The temporary system was used successfully during that outage. IRs 50-321,366/93-03 and 93-05 contain a detailed report of the inspectors reviews and observations of the temporary system.

During the Unit 2 refueling outage, the licensee completed DCR 93-31, which installed and tested a new permanent decay heat removal system (DHR). The new system consisted of an improved version of essentially the same configuration as the temporary system previously used. The system basically consist of a primary and secondary loop. The primary loop, two 100 percent capacity pumps, takes suction from the spent fuel pool and discharges through a strainer and two heat exchangers back to the spent fuel pool. The majority of the primary loop equipment is located in the Unit 1 reactor building. The secondary loop consist of two forced draft cooling towers and two 100 percent capacity pumps which take suction from the cooling tower basin. The pumps discharge through the heat exchangers and return back to the cooling towers. The majority of the secondary loop is located outside on the roof of the railroad access to Unit 1. A separate portable EDG to provide power in the event of a loss of normal power supply was provided. The system was designed with redundant components or manual operations in the event of component failures.

The inspectors reviewed DCR 93-31 and two special purpose procedures. Additionally, the inspectors attended a training session, conducted by the test engineer, presented to the operators responsible for monitoring and operation of the system. The resident inspector staff also held discussions and was briefed by the engineer concerning the testing metholodogy, monitoring requirements and special precautions and controls that would be initiated during the test. The test was designed to verify the alternate DHR system would remove the residual heat from Unit 2 while in the refueling mode, and to confirm the ability to cool both the Unit 2 SFP, prior to a full core offload, and the Unit 2 vessel, with a nearly fully loaded core. The system was designed with the cooling capacity to cool the irradiated fuel in the SFP and a full core offload. Five thermocouples were strategically located, two in different quadrants of the core, two in different locations of the SFP and one for the DHR system suction, to monitor the temperature profile during the test.

On March 20, the initial test conditions were: the cavity flooded and gates removed to connect the SFP; FPC and RHR/SDC were in service; and the DHR system operating. The highest thermocouple reading indicated approximately 95 degrees F in the reactor cavity. Initially the FPC system was removed from service. The thermocouple indications were closely monitored and temperature readings were recorded every 15 minutes for 2 hours. Following satisfactory results and a stable temperature profile, which indicated the temperatures did not increase, the RHR SDC injection valve was throttled to approximately 1000 gpm and the RHR pump was secured. At approximately 2:30 p.m. the DHR system was the only heat sink for the reactor cavity and SFP. Again, temperature readings were recorded every 15 minutes for 4 hours and every hour thereafter, or as directed by the test engineer, for a total of 12 hours.

During the test it was noted that the primary pump was causing some small vortexing at the pump suction line. The pump flow was reduced to approximately 2200 gpm from the normal 3000 gpm. The vortexing stopped. One of the inspectors observed from the refuel floor that there was good water circulation from the reactor cavity to the SFP. The inspector also noted that the reactor cavity temperature averaged approximately 5 degree F higher that the SFP temperature. The highest temperature recorded was a reactor cavity temperature of approximately 98 degrees F.

Following the test the inspectors independently reviewed the test data and concluded that the DHR system adequately controlled the reactor cavity and SFP temperature. Several days after the test the inspectors reviewed in detail the test data and system performance with the project engineer.

The inspectors closely monitored activities during the majority of the test period. The inspectors concluded that the system performed as expected. The test was well planned and continually monitored by the engineers and operations personnel. The operators were properly briefed prior to and during the test. It was observed that HP coverage was also present during part of the testing. During their earlier reviews of the test procedures, the inspectors had noted that some steps were not specific as to what extent the RHR/SDC and FPC systems were to be secured during the test. These issues were discussed with the engineer. A temporary procedure change was initiated to include additional guidance. The procedure contained instructions for system startup, shutdown and infrequent operations. The infrequent operations section contained numerous subsections that dealt with various component failures such as instrument, valve, and loss of power. The instructions were specific and detailed.

The system was operated throughout the remainder of the inspection. The inspectors routinely observed the system in operation and monitored the performance of the system. The system maintained the SFP temperatures low and thus the refueling floor area temperatures were more comfortable for personnel performing activities. On April 12, a transformer problem resulted in a loss of power to the alternate decay heat removal system. The portable diesel generator had been removed several days before (it was rented). The fuel had been completely offloaded from Unit 2. The Unit 1 FPC system was supplying cooling to the SFP, and the Unit 2 FPC system was inoperable.

The inspectors noted that intermittent problems had been occurring with the Unit 1 FPC system. The alternate DHR system, because of its large heat removal capacity, was performing most of the heat removal. The temperature of the SFP increased only a few degrees during the period that the alternate system was shutdown, and did not approach procedural limits. The inspectors noted that FPC is not safety related or addressed by TS at Hatch. One of the strengths of the alternate DHR system is that there is little dependence on installed plant systems. Removal of the emergency diesel generator degraded the alternate DHR system which was, at the time, a valuable onsite cooling asset.

Review of the logs and discussions with personnel indicated that the operators were been able to promptly restore the alternate decay heat removal system after power was restored. The incident served as a validation of the system recovery procedures.

No violation or deviations were identified.

7. Unit 2 Fuel Inspection (71707) (92701) (92700)

During a significant portion of the Unit 2 operating cycle, the unit was operated at less than 100 percent RTP power due to leaking fuel bundles. IRs 50-321,366/93-03 and 93-05 contain additional details concerning this issue.

During the current Unit 2 refueling outage, the inspectors monitored the licensee's actions in response to the identified fuel leakage. As of April 4, 1994, the licensee had sipped 423 fuel assemblies, resipped 10 assemblies, and identified 2 assemblies with leaking fuel. One of the leaking assemblies, at core location 47-22, was the assembly previously identified by the licensee during flux tilt testing. This assembly was visually inspected. The visual inspection revealed an approximately 3 inch long crack in one fuel pin, approximately 30 inches from the bottom of the pin. Some evidence of pin failure, due to debris-induced fretting, was identified in the upper portion of the pin, which also appeared to have a hydride blister. The licensee concluded that debris-induced fretting was the initiating event for the pin failure. An adjoining pin also had indications of debris-induced fretting, although the damage did not extend through the entire thickness of the cladding. Debris was found in the lower portion of the fuel assembly. The second assembly with leaking fuel, core location 43-22, has not yet been visually inspected. The licensee has sipped all of the assemblies which will be reloaded into the core.

The licensee has also visually inspected 217 additional assembles for debris. The licensee plans to visually inspect a total of 255 assemblies. Significant (metallic in nature) debris was found in five additional fuel assemblies: two metal turnings, approximately 0.5 inches long; two pieces of wire; and a metallic piece. The debris was located in "once-burned" bundles. The licensee has concluded that the debris was probably introduced during Cycle 10 maintenance activities. The licensee may reconstitute 3 of the 5 assemblies.

The licensee has decided to discharge (not reload) 140 assemblies (twice and thrice burned) because they were in the core at the time of the suspected debris intrusion.

The inspectors observed activities associated with the fuel movement from the reactor cavity and spent fuel to the sipping cans and inspection stand. Discussions were conducted with the technicians involved in the inspection and with licensee management. Photographs of the damaged fuel were also viewed. The inspectors concluded that the activities associated with the fuel inspection (sipping and inspection) were performed in an appropriately controlled manner.

No violations or deviations were identified.

8. Safety Review Board Meeting (40500)

On March 23, 1994, an inspector attended an SRB meeting (H94-01) held at the corporate office, Birmingham, Alabama. The SRB members in attendance were:

J. T. Beckham - Vice President, Plant Hatch (Chairman)
W. C. Carr - Manager, Environmental Services
W. D. Drinkard - Manager, SAER
K. S. Folk - Manager, BWR Core Analysis
J. D. Heidt - Manager, Nuclear Engineering & Licensing (by phone)
L. K. Mathews - Manager, Inspection and Testing Services
G. D. McGaha - SCS Hatch Engineering Manager
H. C. Nix - General Manager Nuclear Support
H. L. Sumner - General Manager, Plant Hatch (by phone)

These members are designated as primary members, or approved alternate members of the SRB. While all of the members are closely involved with Plant Hatch, some also have direct line responsibility for operation of the units. The SRB members are highly experienced in regards to Plant Hatch operations and clearly have the experience to review and audit Hatch operations.

Members of the SRB were provided with a SRB Review Package several weeks in advance of the meeting. The package is provided so a detailed review may be performed. The review package for this meeting consisted of 3 volumes and was dated January 3, 1994. The SRB review of required items is conducted through a "by exception" process during the meeting. Categories of items consisted of special topics, reports, special reports, past SRB minutes, open items, PRB process, LERs, violation response, proposed changes, DCRs, and safety evaluations. A short presentation was made on the new Decay Heat Removal System. Additionally, during the meeting, the chairman led a discussion on the Hatch Unit 1 HPCI Bearing Failure Event and the Loss of Shutdown Cooling Event for Unit 2. Several SRB "open items" were issued for followup actions as a result of the meeting.

The inspector reviewed the requirements of TS 6.5.2 (Units 1 and 2), ANSI N18.7 - 1976, Hatch QA manual, and the Hatch SRB Procedures Manual. The requirements regarding composition and responsibilities of the SRB as stated in these references are being met. Some of the review requirements are met by the members reviewing PRB meeting minutes. The inspector also discussed several specific SRB functions with the SAER manager. The inspector noted that specific questions asked by several board members indicated that they had performed a detailed review of the SRB package. During the review of safety evaluations, several comments were made and SRB followup items were identified. The inspector concluded that the SRB meeting met all of the applicable requirements and that the SRB is providing adequate review and auditing of Plant Hatch operations.

No violations or deviations were identified.

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

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

a. (Closed) LER 50-321/93-07: Inappropriate Jumper Placed by Plant Personnel Results in Unplanned ESF Actuations. This LER addressed an event when several Group 2 PCIS valves closed unexpectedly on two occasions approximately 20 minutes apart. During the performance of Surveillance Procedure 42SV-E11-004-1S, Residual Heat Removal Shutdown Cooling LSFT, the engineer performing the test placed the required jumpers on the relay contact arms instead of the terminal screw heads. The actions of the engineer in placing the jumper on the contact arm momentarily opened the relay contact and caused the first partial ESF actuation. When the engineer removed the jumpers this also caused the contact to open and the second partial ESF actuation resulted. As part of the correction action, engineering personnel who performed LSFTs were made aware of the event and were instructed not to install jumpers on relay contact arms. The inspector's observations of LSFT this outage has not identified any similar deficiencies. Based on this review, this LER is closed.

b. (Closed) LER 50-366/93-08: Turbine Stop Valve Failure Results in HPCI System Inoperability. This LER addressed an occurrence when, on November 3, 1993, the HPCI Turbine Control Valve was noted as not being in the fully closed position. This item was discussed in detail in IR 50-321,366/93-26. The licensee made the necessary repairs to the valve and the HPCI system was returned to service on November 5, 1993. Based on the repair activities discussed in IR 50-321,366/93-26, this LER is closed.

c. (Clos- ;' ;IO 50-321,366/93-08-02: Failure to Perform TS Surveillance on 1B EDG. This violation was issued after a number of problems were identified involving the timeliness of TS surveillance test performances. Discussions of these problems were documented in IRs 50-321,366/93-08, 93-02 and 92-34. The licensee issued LER 50-321/93-02 to report the missed TS surveillance test and the LER was closed in IR 50-321,366/93-27. The 1B EDG is the swing diesel and was affected by both Unit 1 and Unit 2 TS. The inspector reviewed the licensee's response, dated July 27, 1993. The response stated that the cause of the violation was a change in the surveillance tracking and scheduling computer program data base entry. This change caused the 1B EDG Surveillance test to be rescheduled past the next due date. The oversight was identified by the system engineer during a system performance review. The computer program for tracking and scheduling and the personnel involved have functioned adequately in that no late surveillances have been identified during the last several months. Based on this performance, this violation is closed.

d. (Closed) IFI 50-321/93-05-03: Reactor Vessel Level Instrument Line Crack. This IFI was initiated during the Unit 1 March 1993, refueling outage. During preparations to perform inspection activities on a reactor vessel feedwater nozzle, the licensee identified a small through wall leak on an instrument line (N11B vessel penetration). This issue was discussed in IR 50-321,366/93-05. The licensee replaced parts of the instrument line. GE performed an analysis of the removed line and determined the cause was IGSCC in an area of cold working resulting from machining during vessel fabrication. The nozzles were added to the ISI program. The licensee conducted fluorescent liquid penetrant examination (PT), where possible, and visual inspection (VT) of 7 similar nozzles on Unit 2 during this outage. No discrepancies were identified. The inspectors reviewed the results of the GE analysis, the licensee's corrective actions and the licensee's documentation concerning this issue, and the results of the 7 nozzle inspections. Based upon this review, the licensee's corrective actions and absence of identified problems during the inspection, this IFI is closed.

8. Exit Interview

The inspection scope and findings were summarized on April 18, 1994, with those persons indicated in paragraph 1 above. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

Item Number	Status	Description and Reference
50-366/94-08-01	Open	VIO - Insufficient Verification of Bundle Location During Fuel Movement, paragraph 2c.

9. Acronyms and Abbreviations

A/E - Architect Engineer
AGM-PO- Assistant General Manager - Plant Operations
AGM-PS- Assistant General Manager - Plant Support
ANSI - American National Standard Institute
ARP - Alarm Response Procedure
ATTS - Analog Transmitter Trip System
BWR - Boiling Water Reactor
CFR - Code of Federal Regulations

CR - Control Room
CST - Condensate Storage Tank
DC - Deficiency Card
DCR - Design Change Request
DHR - Decay Heat Removal
DW - Drywell
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EHC - Electro Hydraulic Control
ERT - Event Review Team
ESF - Engineered Safety Feature
EST - Eastern Standard Time
F - Fahrenheit
FPC - Fuel Pool Cooling
FSAR - Final Safety Analysis Report
FT - Functional Test
FT&C - Functional Test and Calibration
GE - General Electric Company
gpm - Gallons Per Minute
HP - Health Physics
HPCI - High Pressure Coolant Injection System
I&C - Instrumentation and Controls
IFI - Inspector Followup Item
IGSCC- Intergranular Stress Corrosion Cracking
IN - Information Notice
IR - Inspection Report
IRM - Intermediate Range Monitor
ISI - Inservice Inspection
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LSFT - Logic System Functional Test
MCC - Motor Control Center
MG - Motor Generator
MGU - Motor Gear Unit
MSIV - Main Steam Isolation Valve
MWe - Megawatts electric
MWO - Maintenance Work Order
NCV - Non-Cited Violation
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
NSAC - Nuclear Safety and Compliance
PCIS - Primary Containment Isolation System
PEO - Plant Equipment Operator
P&ID - Piping and Instrumentation Drawing
PM - Preventive Maintenance
PM&MS- Plant Modifications and Maintenance Support
PRB - Plant Review Board
psig - Pounds Per Square Inch
PSW - Plant Service Water System
PT - Penetrant Test
QA - Quality Assurance

QC - Quality Control
RB - Reactor Building
RCIC - Reactor Core Isolation Cooling System
RCS - Reactor Coolant System
RFPT - Reactor Feed Pump Turbine
RHR - Residual Heat Removal
RHRSW- Residual Heat Removal Service Water System
RO - Reactor Operator
RPS - Reactor Protection System
RTP - Rated Thermal Power
RX - Reactor
SAER - Safety Audit and Engineering Review
SBGT - Standby Gas Treatment
SCS - Southern Company Services
SDC - Shutdown Cooling
SFP - Spent Fuel Pool
SOS - Superintendent of Shift (Operations)
SPDS - Safety Parameter Display System
SRB - Safety Review Board
SRO - Senior Reactor Operator
SRM - Source Range Monitor
SRV - Safety Relief Valve
SS - Shift Supervisor
STA - Shift Technical Advisor
TS - Technical Specifications
URI - Unresolved Item
V - Volts
VT - Visual Test