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

Report Nos.: 50-321/95-23 and 50-366/95-23

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: October 1 - November 11, 1995

Inspectors: For R. W. Wright 12/4/95
Bob L. Holbrook, Sr. Resident Inspector Date Signed

For R. W. Wright 12/4/95
Edward F. Christnot, Resident Inspector Date Signed

Accompanying Inspector: James A. Canady

Approved by: Pierce H. Skinner 12/6/95
Pierce H. Skinner, Chief, Date Signed
Reactor Projects 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: October 1-6, 10-14, 16, 18-19, 21, 24-27, November 1-6, and 11, 1995.

Results: One violation for failure to follow procedure, one non-cited violation, and one unresolved item were identified.

Operations:

The violation for a failure to follow procedure occurred during fuel oil transfer from a tanker truck to the 1A emergency diesel generator fuel oil storage tank. A valve that was required by procedure to be closed was discovered to be open. Operator's continued inattention to detail and personnel errors due to a failure to follow procedures are a concern (paragraph 2.f).

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Unresolved item 50-321,366/95-23-02: Problems with equipment operability from the remote shutdown panel (RSDP) was identified. On November 2, 1995, while unit 2 was in cold shutdown, maintenance troubleshooting activities at the RSDP resulted in the simultaneous opening of the residual heat removal loop B torus suction valve and the shutdown cooling valve. This created a drain path from the reactor vessel to the suppression pool and resulted in an inventory reduction. A special inspection team consisting of three inspectors was dispatched to the site on November 3 to review the circumstances involved with the drain down event (paragraph 2.i).

The inspectors concluded that operator actions during the runback of the 1A recirculation pump caused by main switchyard problems was very good. The inspectors also concluded that the installation of new devices in the switchyard to assist in predictive maintenance monitoring was good (paragraph 2.b).

The inspectors concluded that the actions taken to inspect and clean the suppression pool were very good and management was actively involved. The inspectors concluded that the debris found in the suppression pool did not present a significant risk for emergency core cooling system suction strainer blockage (paragraph 2.d).

The inspectors concluded that operations and engineering personnel were aware of safety relief valve leakage and were implementing satisfactory evaluations and procedural controls. The inspectors concluded that management's assessment and conclusion that no concern for continued operation existed, was reasonable (paragraph 2.e).

The inspectors concluded that the event review team recommendations related to transformer cooling fan problems in the switchyard were appropriate and actions to replace the transformer cooling fans were good. However, overall licensee performance to correct switchyard problems that caused several plant transients was not timely (paragraph 2.h).

Maintenance:

The inspectors concluded that the integrated leak rate test was conducted in the manner prescribed by the procedures; adequate instrumentation was used and acceptable technical supervision was provided (paragraph 3.d).

Engineering:

Non-Cited Violation 50-366/95-23-03: Inadvertent engineered safety feature actuations during testing was identified. The inspectors concluded that engineering inattention to details in the use of procedures resulted in inadvertent starts of the emergency diesel generators on two separate occasions (paragraph 4.d).

The inspectors concluded that the oversight of the inspection of irradiated fuel assemblies for debris and the supervision for the movement of the assemblies for inspection was satisfactory. The additional verification of fuel assembly location in the spent fuel pool by reactor engineering was reasonable and satisfactory (paragraph 4.a).

The inspectors concluded that the licensee's refueling methodology, with respect to heat load removal capability, was bound by the final safety analysis report (FSAR). What the FSAR described as the maximum heat load condition, was consistent with what the licensee does during a normal routine refueling outage (paragraph 4.e).

Plant Support:

Health physics radiological controls were observed and monitored during refueling activities. The inspectors did not note any radiological hazards or other deficiencies (paragraph 2.c)

REPORT DETAILS

1. Persons Contacted

Licensee Employees

J. Anderson, Unit Superintendent
D. Bennett, Chemistry Superintendent
J. Betsill, Unit 2 Operations Superintendent
*K. Breitenbach, Engineering Supervisor
C. Coggins, Engineering Support Manager
D. Crowe, Hatch licensing Manager, Southern Nuclear
*S. Curtis, Superintendent Operations Support
D. Davis, Plant Administration Manager
D. Dees, Operations Shift Supervisor
*P. Fornel, Maintenance Manager
O. Fraser, SAER Supervisor
E. Gibson, Reactor Engineering Supervisor
R. Godby, Maintenance Superintendent
*R. Grantham, Acting Training and Emergency Preparedness Manager
J. Hammonds, Regulatory Compliance Supervisor
*W. Kirkley, Health Physics and Chemistry Manager
*L. Lawrence, Nuclear Specialist (SAER)
J. Lewis, Training and Emergency Preparedness Manager
R. McGinn, Security Operations Supervisor
*T. Metzler, Acting Manager Nuclear Safety and Compliance
*C. Moore, Assistant General Manager - Operations
*J. Payne, Senior Engineer
J. White, Plant Operator
D. Read, Assistant General Manager - Plant Support
R. Reddick, Emergency Preparedness Coordinator
*P. Roberts, Outages and Planning Manager
*J. Robertson, Acting Manager, Mods and Maintenance Support
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

Supporting Inspectors

M. Miller, Division of Reactor Safety, Maintenance Branch, Region II

T. Ross, Senior Resident Inspector, Plant Farley, Division of Reactor Projects, Region II

P. Steiner, Division Reactor Safety, Operator Licensing and Human Performance Branch, Region II

* Attended exit interview

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

2. Plant Operations (71707) (60710) (71711) (71750) (92901) (92904) (93702)

a. Operations Status and Observations

Unit 1 began the report period at 100% RTP. Power decreased to approximately 82% on October 19 due to a runback of the 1A reactor recirculation pump. The runback was caused by problems with the Duval Black AIM. Power was returned to 100% the same day. Reactor power was reduced to approximately 70% RTP on October 28, to repair a leak on the A string 7th stage heater level control valve. A routine control rod sequence exchange was also completed at the reduced power level. Reactor power was returned to 100% RTP on October 30, and remained there for the rest of the report period with the exception of scheduled power reductions for routine testing.

Unit 2 began the report period in day 9 of the 12th refueling outage. The unit remained in a refueling status for the remainder of the report period.

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
Cooling Tower Area	Unit 2 Drywell

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. Unit 1 Recirculation Pump 1A Runback

On October 19, the inspectors heard a loud noise in the 500 KV switchyard. An inspector proceeded to the CR to observe operator actions and investigate the problem. The inspector observed that the RR pump 1A on unit 1 had decreased in speed and reactor power was stable at approximately 82% RTP.

The inspector observed the RR pump speed, core flow, reactor power and confirmed that no reactor power instabilities existed. Operators had also verified the region of potential instabilities was not entered.

Operators informed the inspector that the RR runback occurred at the same time the power system dispatcher, in Atlanta Georgia, opened the Duval Black Shunt Reactor AIM switch. The CR operators also observed the ampere readings on phase one and two of the 500 KV line oscillating for approximately two to three seconds and phase three indicated no amperes. In addition to the RR pump runback, all four trains of SBGT automatically started and normal containment ventilation isolated. Line PCB's tripped open and isolated the Duval Black line. No other plant systems were affected by the problem.

One inspector proceeded to the 500 KV switchyard to observe licensee activities. The inspector did not observe any visible damage to any switchyard equipment. Maintenance personnel later informed the inspectors that the AIM contactor blades did open. However, one phase circuit interrupter, a contained component filled with SF-6 gas, failed to function and did not properly interrupt the circuit. On November 23, 1995, maintenance personnel identified the root cause of the problem as a failed pen on the interrupter head linkage for one phase. This failure prevented proper operation of the circuit interrupter.

The inspectors noted that similar transients occurred on both units on July 27, 1995, when a different AIM on the Duval line failed to completely open. This problem is documented in IR 50-321,366/95-16.

An AIM problem caused almost identical transient in 1989. The inspectors noted that the three AIM failures were not similar in that each failure was caused by a different switch component.

Plant maintenance personnel were not responsible for switchyard maintenance activities. Off-site line maintenance personnel scheduled and conduct these activities. PM activities were completed for all the AIMs, following the problem on July 27, 1995.

The inspectors discussed this problem, and other recent switchyard problems that caused plant transients, with licensee management. The inspectors also attended a meeting between site management and line maintenance management personnel to discuss recent switchyard problems. Site management emphasized the importance of root cause determination and corrective actions. The AIM vendor was on-site to assist with the failure analysis and root cause determination for the recent AIM problem.

The inspectors were later informed by plant management that all AIM interrupter heads would be replaced. The newer installations included devices to assist in predictive maintenance monitoring. The intent is to determine when the interrupter heads should be replaced, before failure. The type of failure that occured would not have been detected by existing PM activities.

The inspectors concluded that operator actions during the transient were very good and that the new design being installed to improve predictive maintenance should minimize the failures of the AIMs.

c. General Refueling Activities

Operations personnel began Unit 2 reactor defueling activities on September 26 and completed fuel off-load on October 1. Reload activities were initiated on October 24 and were completed on October 28. The inspectors reviewed the following procedures: 42FH-ERP-014-OS, Fuel Movement, Revision 11; 34FH-OPS-001-OS, Fuel Movement Operations, Revision 0; and Interoffice correspondence titled, Policy on Management Expectations Concerning Fuel Movement Activities, and verified actions were conducted in accordance with these procedures. The inspectors routinely observed fuel movement activities from the CR, refueling bridge and refueling floor. The inspectors observed that the refueling crews completed the core off-load and reload with no fuel movement errors. The inspectors observed extensive management involvement and oversight during fuel movement activities.

On October 3, outage personnel completed activities to backfeed the Unit 2 main bank transformers. This infrequent activity was completed to align off-site power to inhouse loads so maintenance activities could be completed for the startup transformers. The inspectors reviewed validation procedure 52GM-S11-001-2S, Back feed of Unit 2 Main Bank Transformers, attended the prejob briefing, and observed part of the back feed alignment activities. The inspectors observed that the prejob briefing was thorough, comprehensive and well presented. Management attention to this critical activity was commensurate with its importance.

The inspectors made three separate DW entries. During these entries the inspectors toured the DW to observe general conditions, work activities, HP control points and other radiological controls. The inspectors reviewed the work associated with the installation of DCRs 93-059, Install Incore Corrosion Monitoring System and 91-030, Install Reactor Recirculation System Decontamination Ports, and maintenance activities involving the replacement of a DW cooler fan was also observed. During the second entry the inspectors noted that duct tape was sticking on the blow down openings to the torus. A roll of duct tape, a hard hat, and unattended tools were observed in the same area. The inspectors reported these findings to the licensee's outage coordination group.

A subsequent entry after the completion of drywell work activities observed that the duct tape, hard hat, and tools observed during the previous entry had been removed. During these entries, the inspectors did not identify any deficiencies related to the DCR installations, work activities, or any industrial or radiological safety hazards.

The inspectors did not identify any specific concerns or deficiencies.

d. Unit 2 Suppression Pool Inspection and Cleaning

On September 28, the condition of the ECCS suction strainers was video taped for future evaluation. Divers completed an inspection of the suppression pool and initiated de-sludging activities. The divers also spot painted specific areas of the surface. The suppression pool was totally vacuumed cleaned on three occasions. The inspectors observed diver activities, reviewed the licensee's report that documented debris found and analysis of the sludge identified in the suppression pool. The inspectors also observed debris found in the suppression pool, and discussed diver activities and clearliness of the suppression pool with members of licensee management.

The report identified the general cleanliness and debris found for each of the 16 bays that make up the suppression pool.

No debris was found in bays 2, 3, 8, 11, and 14-16. The total surface area identified for possible ECCS suction strainer blockage was about 133 square inches or 0.923 square feet. This was significantly smaller that the surface area of one ECCS suction strainer.

Management informed the inspectors they believed that much of the debris, such as tape, tie wraps and small pieces of wood was due to ongoing work activities during the current refueling outage. However, they planned to review applicable procedures and make changes to the foreign material exclusion control.

The total sludge removed from the suppression pool was about 293 cubic feet of wet fluffy material. A sample of the sludge was sent off-site for laboratory analysis. The sludge particles themselves were too small to cause suction filter blockage.

A light film of sludge was found on the strainers prior to the desludging process. None of the holes in the strainers were clogged. Depressions and shallow indentions were noted in the surface of seven of eight RHR pump suction strainers. No splits or cracks were found on any of the strainers. The licensee believed the indentions were due to strainer removal for other maintenance activities within the suppression pool. The licensee's evaluation determined that the indentions did not have a detrimental impact on the ability of the strainers to perform their function. A video of the suction strainers was taken after completion.

The inspectors reviewed FSAR section 6.3.2.14, ECCS NPSH Margin, and concluded the amount of debris identified for possible suction strainer blockage did not present a significant potential to render the ECCS system inoperable due to insufficient NPSH. The FSAR NPSH calculations, for any particular ECCS system, indicated adequate NPSH margin existed assuming one strainer 100% blocked and the second strainer 50% blocked.

The inspectors concluded the licensee actions taken to inspect and clean the suppression pool were very good and management was actively involved. The inspectors concluded that the debris found in the suppression pool did not present a significant risk for ECCS suction strainer blockage.

e. Review of Unit 1 Leaking SRV

The inspectors observed that Unit 1 SRV tail pipe temperature recorder indicated elevated temperatures for five SRVs. The inspectors also noted from the CR operator logs that RHR suppression pool cooling had been placed in service approximately seven times in October and November. The logs also documented that some individual suppression pool temperature instruments had failed the TS channel check when compared to the average bulk suppression pool temperature. This was due to suppression pool water stratification.

The inspectors discussed the issue with operations personnel. The operators informed the inspectors that suppression pool cooling was placed in service to promote mixing and reduce stratification. The operators also informed the inspectors that they reduced suppression pool level occasionally and suspected the level increase was due to leaking SRVs. Operators were aware that some SRVs were leaking, but they did not remember which ones or how many SRV's were leaking. The operators were very knowledgeable of the control room instrumentation and TS requirement for suppression pool temperature.

The inspectors review of procedure 34SV-SUV-019-1S, Surveillance Checks, Revision 26, did not identify any instance where TS requirements for suppression pool temperature was not met. During the performance of the procedure operations personnel identified that stratification of the suppression pool had occurred. They corrected the problem by placing suppression pool cooling in service.

The inspectors discussed the five SRVs that had increased tail pipe temperatures with engineering. The system engineer stated that any SRV tail pipe temperature in excess of 200°F was suspect of leakage. The inspectors noted all five SRVs indicated a temperature greater that 200°F. A concern for continued unit operation was not expressed by engineering or operations personnel.

IR 50-321,366/94-15 documented previous SRV leaking problems. At that time the inspectors identified that Unit 2 SRVs had indications of elevated tail pipe temperatures. The inspectors noted that four Unit 2 SRV valve bodies were shipped off-site for maintenance repairs during the current refueling outage. Engineering personnel stated that it was standard practice to perform outage maintenance activities on any SRV that displayed indications of leakage.

The inspectors verified that applicable procedures were used when indications of leakage occurred. In some cases the alarm setpoints had been increased due to the leaks. This reduced continued alarms in the CR. For the cases the inspectors reviewed, engineering personnel were aware of the SRV leakage and setpoint changes. Engineering and operations reviewed alarm setpoint changes and provided written reviews and evaluations for the changes.

The inspectors concluded that operations and engineering personnel were aware of SRV leakage. Evaluations and procedural controls were being implemented. The inspectors concluded that managements assessment and conclusion that no concern for continued operation existed, was reasonable.

f. EDG Fuel Oil Spill

On October 13, 1995, fuel oil from a tanker truck was inadvertently pumped into the EDG 1A day tank. This resulted in approximately 350 gallons of fuel overflowing the day tank and partially flooding the day tank room. The inspectors reviewed applicable procedures, observed the affected area and discussed the occurrence with licensee personnel. The procedures reviewed were: 34SO-R43-001-1S, Diesel Generator Standby AC System, Revision 16, Section 7.4.1, Transfer of Fuel Oil Between Storage Tanks; and 34GO-OPS-056-OS, Receipt of Diesel and Auxiliary Boiler Fuel Oil, Revision 4. The review and discussions indicated that the normal process for receiving fuel was to transfer fuel from the 1A storage tank to the other four storage tanks as necessary, and align the system to place any new fuel into the 1A tank only. Section 7.4.1 of procedure 34SO-R43-001-1S, provided a step by step process for transferring fuel oil between storage tanks. This section contained a step which stated: WHEN transfers are complete, return the Fuel Oil Transfer System to Standby by completing Attachment 7. Attachment 7, Diesel Generator Fuel Oil System Restoration, contains a list of valves with their normal positions and had "CHECKED BY" and "VERIFIED BY" initial blocks. Valve 1R43-F006A was required to be closed and verified as closed. This was the valve that was discovered open after the fuel oil day tank over flowed. Post reviews indicated that attachment 7 had not been performed properly. When the tanker truck started transferring fuel oil, the fuel went to both the 1A Storage Tank as well as the 1A Day Tank, resulting in the overflow.

The inspectors discussed the problem with operations management. The licensees review of the problem identified performance deficiencies as well as areas for procedural improvements. Even though the procedure was used numerous times to transfer fuel oil with no recent errors, the licensee determined the procedure wording could be improved.

This failure to follow procedure had very little safety significance with respect to EDG operation or availability. The fuel oil overflow and cleanup efforts slightly increased fire and personnel hazard conditions. Operations personnel continue to demonstrate weaknesses in attention to detail and incorrect use of procedures. IR 50-321,366/95-18 and 95-22 document other recent examples of operations personnel failure to follow procedure. As a result, this is identified as violation, VIO 50-321,366/95-23-01: Operations Failure to Follow Procedure While Transferring Diesel Fuel Oil.

g. DCR Training for Operations

The training department conducted several sessions of DCR training for operations personnel before Unit 2's startup, following the refueling outage. The training was conducted to inform operators of system and component changes made during the refueling outage. The inspectors reviewed lesson plan SO-LP-75210-00: Unit 2 1995 Outage DCRS, and attended part of two training sessions. Part of the training was conducted using the plant specific simulator. The inspectors noted the training material contained learning objectives, description and reasons for the design changes, and the significance and consequences of the changes. The material also identified and discussed procedures and operator actions that were affected. Simulator modeling and hardware changes were implemented to mimic some of the design changes.

The inspectors concluded that the sessions were well organized and the training materials and presentations were excellent. The materials were current and accurately reflected plant changes. The inspectors also concluded that the use of the simulator for active hands on training which provided immediate feedback was excellent.

h. Partial Loss of Unit 1 FW Heating

On November 7, a partial loss of FW heating occurred on Unit 1. A hard ground was received on the 1B 600 Volt bus. A main transformer fan grounded and caused a loss of Control Building MCC 1D, Water Treatment MCC 1B, and a trip of the 1B heater drain pump. Operators used procedures 34AB-N21-001-1S, Loss of Feedwater Heating, Revision 1; and 34AB-R23-001-1S, Loss of 600 Volt Bus 1A, 1AA, 1BB or 1B, Revision 0, to correct the problem. Reactor power was manually reduced as required by procedure. FW heating was restored and reactor power was returned to 100% RTP in about three and a half hours. The inspectors did not identify any core thermal limit concerns following the brief loss of FW heating.

IRs 50-321,366/94-31 and 95-16 documented several previous examples where switchyard problems including transformer cooling fans caused grounds that resulted in plant transients. The inspectors discussed this problem as well as the previous problems with licensee management. As part of the licensee's corrective actions for previous fan problems, many of the cooling fans were rebuilt off-site and replaced by line maintenance personnel. However, the performance of the rebuilt fans was not satisfactory. They demonstrated a higher failure rate than the older existing fans.

An ERT was initiated to review the transformer cooling fan problems and make recommendations for corrective actions. Part of their recommendations was to replace all the rebuilt fans and other long life fans that may be subject to failure. Some fans were replaced on both units. Plans were to replace Unit 2 fans during the upcoming startup activities.

The inspectors concluded that the ERT recommendations were appropriate and actions to replace the transformer cooling fans was good. However, overall licensee performance to correct switchyard problems that caused several plant transients was not timely.

i. Unit 2 Inadvertent Loss of Reactor Coolant Inventory and Isolation of Shutdown Cooling

On November 2, 1995, while Unit 2 was in cold shutdown with the 2A RHR pump aligned for SDC, troubleshooting activities at the RSDP inadvertently caused both B train RHR pump suction valves (2E11-F004B and F006B) to open simultaneously creating a direct flow path from the reactor vessel to the torus. In about 50 seconds, approximately 10,000 gallons of primary coolant drained from the reactor before it was terminated by the automatic closure of SDC isolation valves (2E11-F008 and F009) due to low reactor vessel level. Narrow range RVWL had dropped from a +60 inches to an SPDS indicated level of minus 8 inches (top of active fuel is at minus 160 inches). RVWL was restored in about 25 minutes, and SDC was resumed five minutes after that. During the event, there was no appreciable increase in reactor coolant temperature. The licensee reported this event to the NRC pursuant to 10 CFR 50.72(b)(2)(i).

On November 3, the site GM requested the AGM-Operations to take direct responsibility for assembling and overseeing an ERT to investigate the inadvertent loss of inventory event. The AGM-Operations was relieved of his normal duties so he could devote his complete attention to the investigation. On November 4, a special inspection team from Region II arrived on-site to conduct an independent inspection of the circumstances leading up to and surrounding the event. As part of this inspection, the team intended to determine and/or confirm the root cause(s), assess the operator's response to the event, and evaluate the licensee's ERT efforts and management involvement. The team completed its inspection on November 6, and exited with plant management. The following paragraphs summarize the team's findings and conclusions based on interviews with the actual event participants; plant walkdowns; reviews of applicable procedures, drawings, and operator logs; and discussions with the ERT.

On October 25, a week before the inadvertent loss of inventory event, operators had attempted unsuccessfully to open MOVMR F006B (SDC suction isolation valve for the 2B RHR pump) from the RSDP IAW 34SV-E11-002-2S, Revision 16, "RHR Valve Operability," as part of the new ISTS SR 3.3.3.2.2. This valve had not been stroked from the RSDP since 1978. MWO #29503317 was written to investigate why F006B would not open from the RSDP and make necessary repairs. Coincidentally, on October 30, reactor operators in the control room noticed anomalous VPI behavior by F004B while it was being stroked for reasons unrelated to surveillance testing. MWO #29503388 was written to resolve this additional problem.

On November 2, electricians arrived at the control room with both MWOs to troubleshoot MOVs F004B and 6B. Both valves were successfully stroked open and closed from the control room. Two non-licensed PEOs and an electrician were then sent to the RSDP to stroke F006B, while the CBO remained in the control room to direct valve manipulations at the RSDP. Without verifying RSDP switch positions first, the CBO directed the PEO at the RSDP to energize that portion of the RSDP which controlled valves F004B, 6B, and 6D by positioning transfer switch S-10 from NORMAL to EMERGENCY. This transferred control and VPI of these valves to the RSDP and removed all control and visible VPI from the control room. Unbeknownst to the CBO and PEO, the F004B valve should have immediately stroked open at that moment, because its control switch was selected to its normally OPEN position consistent with the at power, standby lineup of the RHR system. However, F004B did not open due to an unknown problem with its protective interlock logic (discussed later). Although the CBO requested valve position status from the PEO at the RSDP before proceeding, he did not request relative switch positions. The PEO informed the CBO that all the valves were closed. Neither the CBO or PEO recognized the F004B control switch was selected to OPEN. The CBO then directed the PEO to open the F006B valve. At 9:30 p.m., the PEO took the F006B control switch to OPEN, and immediately both F006B and F004B valves began to open. The PEO, confused and alarmed that both valves were stroking OPEN, promptly took both valve control switches to the CLOSE position which had no effect because both MOVs were designed with "seal-in" logic features. It was at this time that the PEO realized the F004B control switch was in the OPEN position.

The second PEO, on the phone with the CBO, reported that both valves were stroking open. The CBO directed the RSDP PEO to shut the valves and transfer control back to the control room. The PEO informed him that both switches were already placed in the CLOSE position, and transferred valve control back to the control room where the CBO was also unable to halt the valves from opening. The valves continued to stroke open until they reached full open, whereupon they began to close. The stroke time of these valves is between 100 and 110 seconds. Before F004B and 6B were fully open, RVWL had drained below the +3 inch setpoint which initiated a reactor scram (rods were already fully inserted) and Group 2 isolation that shut F008 and F009 terminating the event and isolating SDC. During the inadvertent loss of inventory, the CBO directed both PEOs to open 2E11-F083 and 84 which would lineup flow to the reactor via the condensate transfer system. However, this proved unsuccessful because, after MOVs F008 and F009 went shut, the injection path was blocked. The CBO then directed both PEOs to open F081A and 82A. This action created a successful flow path from the condensate transfer system, and RVWL was restored.

Almost immediately after the initial inventory loss was isolated, the SS returned from behind the control panels to the "at the controls" area. He promptly recognized the event conditions and entered 34AB-C71-001-2S, "Scram Procedure," 34AB-E11-001-2S, "Loss of Shutdown Cooling," and EOP flow chart 31EO-EOP-010-2S, "RC RPV Control (Non-ATWS)." At 9:44 p.m., the reactor scram and Group 2 isolation were reset, and by 9:55 p.m., the RV was reflooded to greater than 53 inches. At 10:00 p.m., the 2A RHR pump was restarted and SDC reestablished. The RCS temperature of 163 degrees F and pressure of 0 psig remained constant throughout the event. All automatic safety systems performed as designed. Except for the F004B interlock failure, there were no other equipment malfunctions during and following the loss of RVWL. Furthermore, in response to the event, the operating crew properly implemented applicable emergency and abnormal operating procedures in a timely manner to restore the unit to a safe and stable condition.

Shortly before the inspection team arrived on-site, the licensee's ERT discovered what they considered to be the root cause. The limit switch for MOV F006B that feeds into the RSDP interlock logic of F004B was mislabelled and improperly setup. The F004B interlock was designed to prevent the F004B valve from opening when the F006B valve was OPEN. However, as-installed F006B limit switch configuration defeated this interlock. The interlock worked in reverse, it would only allow the F004B valve to open when the F006B valve was not open (i.e, off its fully closed seat). Electricians had found the RSDP interlock for F004B wired to the F006B limit switch position labelled as #15, instead of to #14 the position required by applicable electrical drawings. However, the electricians also noticed that the F006B limit switch base was incorrectly labelled so that limit switch positions #14 and #15 were switched. This meant, that despite the labelling error, the F006B limit switch was properly wired to position #14 (which was labelled as #15). But, it was further determined that the F006B limit switch rotor had been oriented 90 degrees from its normal alignment. This effectively reversed the electrical contacts which made the limit switch behave as if it were actually wired to position #15 of the drawings. Consequently, the as-wired F006B limit switch that fed the RSDP interlock logic for F004B would work the opposite way it was designed (i.e., F004B could only open when F006B was open).

The F004B and 6B RSDP valve interlock was originally installed as part of MR #2-78-1316, which provided instructions for implementing internal wiring changes to the RSDP (2C82-P001). These wiring changes were incorporated to add valve limit switch interlocks for valves 2E11-F004B and F006A, B, C, and D as specified by DCR #2-78-142, Revision 1, dated April 12, 1978. DCR 2-78-142 was initiated to incorporate the interlocks specified by General Electric Field Deviation Disposition Request HT2-276, Revision 1, dated April 3, 1978. The valve control interlock circuitry of F004B was to be wired to the F006B limit switch at position #14 which is a normally closed contact. The purpose of this interlock was to prevent F004B from opening unless F006B was fully closed. The inspectors reviewed the functional test procedure specified in MR 2-78-1316, which was signed off as successfully performed on June 3, 1978. The inspectors concluded the functional test for the F004B interlock modification adequately addressed all logic considerations to ensure proper operation. Although it can be stated with some assurance that the interlock worked properly in 1978, in light of the November 3rd discovery it can not be stated with any assurance on how the F006B limit switch was actually setup and wired.

The inspection team reviewed the work history for valve F006B since 1978 to determine if and when the interlock wires could have been altered and not fully functionally tested. The most likely time period was during June 1986 to April 1989. There were at least three opportunities when internal wiring was performed during maintenance work; 1) MWO #28602451 dated June 6, 1986, that replaced internal wiring identified as not meeting EQ specifications;

2) MWO #2884481 dated November 11, 1988, that installed other supplemental interlocks which involved internal wiring; and 3) MWO #28901304 dated March 22, 1989, that replaced the limit switch rotors. The last logic and interlock functional test (Special Test 42SP-111588 PR-1-25) of the F004B and 6B valves was satisfactorily conducted December 12, 1988 from the CR, the RSDP was not used during this functional test. There were no requirements to test the RSDP during this period of time until the new ISTS were in effect July 1995. The team concluded that the F006B limit switch wiring and setup problems could have probably occurred during the period of time discussed above, in which comprehensive RSDP functional testing was not performed.

A team inspector reviewed electrical drawings that included the Unit 2 Elementary Diagram Drawings for H27975, Remote Shutdown System 2C82 and H 27649, RHR System 2E11. These drawings were reviewed to determine and verify the interlock logic was designed and would function as required if the wiring was installed as specified. The team concluded that the interlock logic was adequate and could function as designed. In addition, the inspectors reviewed the licensee corrective action being implemented that involved the inspection of all limit switch wiring. On November 5, 1995, a team inspector observed electricians inspect the limit switch wiring for 2E11-F006A using MWO #29503436 dated November 3, 1995. The electricians were very experienced with these MOVs and performed the wiring inspection in a complete and thorough manner. The inspector verified that the F006B limit switch wiring and rotor setup were installed properly by reviewing completed MWO #29503317 dated November 4, 1995. The team concluded that the ongoing and planned limit switch wiring inspections, special functional testing, and ISTS surveillance testing would confirm applicable RHR MOV interlocks were wired correctly to perform their intended safety function.

Based upon independent inspection efforts the team concurred with the root cause identified by the ERT. However, the inspectors identified a number of personnel performance issues that directly contributed to the inadvertent inventory loss event. Each of these performance issues, either singularly or in combination, represented opportunities to prevent the event. The following contributing factors were identified:

Poor Planning and Lack of Guidance

1) No specific plant procedure was used or referenced to conduct valve manipulations at the RSDP. Applicable MWOs provided no detailed guidance or instructions for performing the troubleshooting.

2) No pre-job brief was held with the SS, CBO, PEOs, or electrician responsible who ended up being responsible for performing valve manipulations and troubleshooting activities at the RSDP.

3) No one was assigned overall control of the troubleshooting activities.

4) The non-licensed PEO assigned to operate the RSDP could not recall when, or if, he had ever operated this panel before, except to hang tags.

5) Lighting of the MOV F004B, 6B, and 6D control switches on the RSDP was marginal.

6) Although the SS and CBO were sensitive to the potential for draining the RV, no particular precautions (except for attempting to ensure F004B remained closed) were taken to isolate that portion of the RHR system being tested.

Inadequate Control and Execution

1) The PEO at the RSDP did not notice that the F004B control switch was selected to OPEN.

2) The CBO failed to verify RSDP MOV control switch positions prior to directing the PEO to operate transfer switch.

3) Miscommunication between the CBO in the CR and the PEO at the RSDP failed to establish actual RSDP MOV control switch positions once the transfer switch was positioned to EMERGENCY.

Lack of Supervision

1) The Unit 2 SS left the "at the controls area" to go behind the MCB panels to pursue other work prior to the PEO manning the RSDP to the begin F004B and 6B troubleshooting.

2) There was no command and control of troubleshooting activities and RSDP valve manipulations by a qualified supervisor.

The inspectors also identified the following personnel performance issues that happened relative to the event, but did not appear to contribute to it:

Non-Contributing Performance Issues

1) Indirect communications were established between the CBO and PEO at the RSDP, via another PEO on the phone some 30-40 feet from the RSDP.

2) The PEO at the RSDP closed the MOV F004B and 6B control switches without the express knowledge and consent of the CBO.

3) SS and CBO logs failed to document the RHR Valve Operability surveillance tests and valve problems with F004B and 6B.

4) Step 7.5.1, of the RHR Valve Operability test procedure had not been signed by a SS when the special inspection team arrived on-site. And yet portions of Section 7.5, "Remote Shutdown Panel Function Checks," were performed on October 21 for MOVs F006A and 6C, on October 25 for MOV F006B. Step 7.5.1 requires the SS to confirm proper plant conditions are established for RSDP testing, and grant approval to proceed with this testing.

5) On November 2, operators inadvertently drained about an inch of RVWL to the torus via the 2B RHR pump minimum flow line while stroking F006B from the control room prior to the event. And again on November 4, while stroking F006B from the RSDP after the event.

Management interest and involvement in this event, including subsequent investigation and inspection efforts by the ERT and NRC special inspection team, was very high. Management support for team inspection and ERT efforts was extensive. As the NRC special inspection team and the ERT developed their conclusions concurrently, management began to initiate prompt corrective actions. Although the ERT did identify the root cause of the event, the contributing and non-contributing factors were identified by the special inspection team. The ERT efforts observed by the team appeared to be equipment failure oriented. However, considering the team's on-site arrival before the ERT was finished, and the direct support provided by the ERT to the NRC which clearly delayed their own efforts, it is difficult to determine what other independent conclusions the ERT might have reached without NRC intervention.

By the end of the teams' special inspection, the licensee was continuing to develop additional corrective actions and awaiting recommendations from the ERT. Also, the licensee had not resolved the original problems related to MOVs F004B and 6B. The reason(s) F006B would not open from the RSDP on October 25 and the anomalous VPI behavior of F004B on October 30 were still unknown.

The inspectors of the resident staff continued to monitor the licensee activities related to the RSDP and observed the resumption of surveillance procedure 34SV-E11-002-2S, RHR Valve Operability, Revision 16. During the observation the inspectors noted that when RSDP transfer switch S14 was placed in the EMERGENCY position double indication for RHRSW pump 2D appeared. The operators immediately stopped the surveillance. From November 9, the date of the observation, to the end of this report period numerous additional deficiencies were identified. The licensee was in the process of identifying and correcting deficiencies at the end of the report period. The inspectors will continue to monitor the licensee's activities in this area. Due to the potential significance of this item and a possible impact on Unit 1, this is identified as an unresolved item, URI 50-321,366/95-23-02: Problems with Equipment Operability from the Remote Shutdown Panel.

One violation and one unresolved item were identified.

3. Maintenance Activities (62703) (61726) (92902) (61720) (61701) (70313)

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 1-95-0913: Request for Repair of Cooling Tower Fan 1W24-C011
2. MWO 2-94-2453: Replace PSW Valve P41-F115B to LPCI Room Cooler
3. MWO 2-95-2101: Replace PSW piping to EDG 2C
4. MWO 1-94-4783: Perform Penetrant Examination on Valve 1E11-F005A
5. MWO 1-95-1754: Repair Core Spray Valve 1E11-F005
6. MWO 1-95-2466: Determine Cause for Low RCIC Discharge Pressure and Low Oil Level
7. MWO 1-95-3751: Investigate Reason for RCIC Trip

8. MWO 2-95-3456: Replace DW Cooler Fan

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)

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. 34SV-R43-006-2S: EDG 2C Semi-Annual, 24 Hour Run and Hot Restart Test.

2. 42SV-R43-020-2S: EDG 2C Logic System Functional Test

3. 34SV-R43-005-2S: EDG 1B Semi-Annual, 24 Hour Run and Hot Restart Test.

4. 42SV-R43-019-2S: EDG 1B Logic System Functional Test

5. 42SV-E21-001-2S: Core Spray Logic System Functional Test

6. 42SV-R42-009-0S: Combined Service-Performance and Modified Performance Tests, Unit 2 SS Batteries

7. 34SV-E51-002-1S: RCIC Pump Operability, Unit 1

8. 53IT-TET-002-0S: Valve Operability Test and Evaluation System

During and following the 24 hour run of the 2C EDG the inspector observed an oil leak. The leak was from the turbo-charger, and was a steady leak. Maintenance personnel tightened the turbo-charger lube oil drain line following the 24 hour run and corrected the problem.

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

c. Breakage of Cooling Tower Fan Blades

On October 16, the inspectors were informed that the fan blades from Unit 1 cooling tower fan, 1W24-C011, had become damaged and one blade was thrown from the fan housing.

The inspectors observed maintenance activities to repair the problem on October 17. A discussion with the maintenance foreman indicated that a shaft bearing between the fan and the gear box was degraded. The foreman believed the bad bearing had enough loose play to allow the fiberglass blading to touch the shroud housing of the fan, resulting in destruction of the fan blading. The inspectors observed through-wall breaks in the fiberglass shroud housing. Minor wood damage was repaired by carpenters.

The inspectors conducted a four year review of MWOs initiated on the fan for cell 11 of cooling tower number one. An MWO dated September 19, 1994, was for the performance of the one year PM on the fan. Some of the work items involved changing the oil in the gearbox, greasing the input and output shaft seals, greasing of motor bearings, and inspection of the motor and gearbox mounting hardware. While performing this PM, it was discovered that the output shaft bearing was worn excessively and the input and output shaft seals were leaking excessively. A DC was initiated to repair the gearbox. MWO 1-95-0913 was initiated April 1995 based upon this DC. The gearbox was not actually repaired until after the blade failures and damage that occurred October 16. No significant problems with the cell 11 fan were identified in the four year review prior to September 1994.

The blade breakage problem did not cause a unit transient nor was it necessary to reduce power on the unit. The system is not safety related; however, there have been problems in the past with the cooling towers that caused plant transients and a scram. The cooling tower problems are discussed in IR 50-321,366/95-06 and IR 50-321,366/95-22.

The inspectors concluded that maintenance personnel took appropriate and reasonable actions to make repairs to the damaged portions of the cooling tower.

d. Unit 2 Primary Containment Integrated Leakage Rate Test

The Unit 2 ILRT began on November 2. The inspectors reviewed the ILRT test package and observed ongoing work activities. The activities were controlled by two procedures, 42SV-TET-005-2S Integrated Leak Rate Test Preparations, Revision 1, and 42SV-TET-003-2S, Primary Containment Integrated Leakage Rate Test, Revision 4. 42SV-TET-005-2S contained instructions for installing temporary test equipment. This equipment included air compressors, special instrumentation, piping, valves, electrical cables and electronic monitoring equipment. The inspectors observed portions of the installation and pretest activities. 42SV-TET-003-2S provided instructions for system lineups, performing the test, and identified the test acceptance criteria. The inspectors reviewed the applicable procedures, discussed the test activities with the test engineer and observed portions of the system valve lineups. The inspectors also noted that special purpose procedure 42SP-062295-OU-2S, Containment Helium Injection, Revision 0, was part of the test package. This procedure allowed the test personnel to inject helium in the primary containment to assist in locating any containment leakage.

The inspector observed portions of the pressurization, stabilization, the actual test, and the verification. Initial results indicated a 0.3175 weight percent per day leakage. This was well below the acceptance criteria.

The inspector concluded that the test was conducted in the manner prescribed by the procedures, using appropriate instrumentation and with acceptable technical supervision.

No violations or deviations were identified.

4. Engineering Activities (37551) (37700) (92903) (37828)

a. Inspection of Fuel Assemblies and the Discovery of Tubular Debris

The inspectors reviewed procedures 42FH-ERP-014-0S, Fuel Movement, Revision 11, and 34FH-OPS-001-0S, Fuel Movement Operations, Revision 0, and observed the inspection of fuel assemblies for debris and corrosion on October 4. Reactor engineering personnel provided oversight for the inspection activities and the inspectors noted that GE personnel conducted the fuel inspection. The inspectors observed that the assemblies inspected were moved from the SFP to the fuel preparation machine with the refueling bridge. The refueling bridge was operated by a RO under the supervision of a SRO. Reactor engineering provided additional verification for the SFP locations.

A total of 22 off loaded fuel assemblies were inspected for debris. 17 of these were inspected for debris by only removing the channel and replacing it after the inspection. The remaining five assemblies were additionally inspected for corrosion. Other items inspected on these five assemblies included finger spring tension, rod to rod spacing, spacers, lower and upper end plugs, flow holes, and fuel rod seating.

Debris was found in four of the 22 assemblies inspected. The licensee indicated that they were not able to identify the source of the debris or its composition. It was concluded by GE and the licensee that the debris found was insignificant due to its size and amount. No significant corrosion or other deviations were found in the five bundles that were inspected in more detail.

The inspectors concluded that the licensee's oversight of the inspection activity and supervision for the movement of the assemblies for inspection was satisfactory. The inspectors also concluded that the additional verification of fuel assembly location in the SFP by reactor engineering was reasonable and satisfactory.

On October 11, during control rod blade change out activities, a small tubular piece of debris was discovered in one of the bundle flow holes of the fuel support piece associated with peripheral control rod 01-31. The tubular debris was approximately three inches in length with an outside diameter of approximately three-quarter inches. Activity of the tube was approximately 600 Mrem/hr at two feet below the water surface. The licensee believed, based upon the high radioactivity reading, that the object had been in place for an extended period of time. Engineering believed the debris could have been tubing from an LPRM removed in the past. The licensee informed the inspectors that there is no known way by which they can determine the source of the debris.

The tubular debris was removed from the fuel support piece, placed in a bucket and stored in the Unit 2 SFP. The inspectors concluded that the actions taken by the licensee upon the discovery of the tubular debris was reasonable and satisfactory.

b. 1B LPCI Inverter Trips Due to Ground

The inspectors continued to monitor the problems with the 1B LPCI inverter. These problems are discussed in IR 50-321,366/95-07 and IR 50-321,366/95-22.

On October 14, the 1B LPCI inverter annunciator in the control room alerted the operators that the inverter had tripped. The operators entered the appropriate TS for the trip. Troubleshooting activities by I&C and engineering identified that a loose wire had rubbed the paint off of a portion of the cabinet that it was touching and caused a ground. This ground caused the output breaker of the inverter to trip. The inspectors discussed this trip with engineering and were told that this trip was not related to the previous tripping problems.

Engineering feels that the troubleshooting activities, which involved the changing out of the annunciator card on numerous occasions, resulted in a cleaning of the card insertion contacts. This cleaning of the contacts appeared to have solved the previously identified problem with the annunciators failure to actuate. Subsequent testing by engineering indicated that the annunciator is functional and will provide an alarm in the control room upon a trip of the 1B LPCI inverter.

Engineering informed the inspectors that the vendor presented a two week training course on how the LPCI inverters operate in general and how they work at Hatch in particular. These inverters were custom built for Plant Hatch. Personnel in attendance at this course were the system engineer and I&C instructors. Engineering personnel stated trouble shooting activities as well as routine maintenance activities would be greatly improved. They expected the availability and reliability of the LPCI inverters to improve.

The inspectors concluded that engineering response and monitoring of the LPCI inverter's tripping and annunciator card problems were satisfactory. Reasonable efforts were taken to solve the problems. The inspectors also concluded that the training on the aspects of the LPCI inverters that are unique to Plant Hatch should be beneficial.

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 a 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
95-049	Modify EDG Logic to Seal in LOSP Automatic Voltage Control
94-017	SMA Modifications
93-059	Install Incore Corrosion Monitoring System
91-030	Install Reactor Recirculation System Decontamination Ports
90-164	Convert RFP Controls to EHC

94-052	Core Shroud Modification
93-068	Replace RCIC Test Valve to CST
92-091	Replace HPCI flow controller with Yokagawas
92-093	Replace RCIC flow controller with Yokagawas
94-013	Install new DW penetration
94-35	Power uprate modifications
94-36	Power uprate modifications

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

d. Inadvertent ESF Actuations During Testing

Two recent ESF actuation occurred during testing. On October 20, while performing procedure 42SV-E21-001-2S, Core Spray Logic System Functional Test, Revision 4, the 2A and 2C EDGs inadvertently started. Step 7.2.9 of the procedure required that jumpers be installed to initiate a simulated LOCA signal. All ECCS equipment affected by the test started as designed.

Immediately after the ESF, operations supervision instructed engineering to remove the jumpers and terminate the test. All equipment that started was monitored for proper operation, stopped and returned to normal standby.

A followup investigation by the engineering supervisor revealed that the emergency power test keylock switch was in the tripped position. Step 7.2.5.1 of procedure 42SV-E21-001-2S required the switch be confirmed placed or placed in the normal position.

The inspectors held a discussion with the operator involved in the performance of the LSFT. 42SV-E21-001-2S is an engineering procedure. Traditionally this type of procedure is conducted by engineers with the assistance of operations for the manipulation of switches and other controls. The operator informed the inspectors that the engineer performing the procedure mistakenly requested him to place the switch to the "tripped" position. The operator further stated that three part communication was used to insure that the engineer's request was understood. The inspectors corroborated the operator's description of the event through a discussion with NSAC personnel responsible for writing the LER for the event. The engineer involved with the problem made an error in his communications. This resulted in the incorrect performance of a procedural step.

The system engineer was immediately disqualified following the event. The system engineer will not be able to independently perform any LSFTs while in a disqualified status. Other corrective actions included assigning a member of engineering management to oversee the performance of other LSFTs. Operations personnel were to have a copy of any engineering procedure when assisting engineering in the performance of LSFTs. The problem was discussed with other engineers performing surveillance tests. The problem was also discussed with all operation's shifts. A remedial plan for the disqualified engineer was being developed.

On October 30, during a restoration step in procedure 42SV-E11-001-2S, Residual Heat Removal System (LPCI) LSFT and Auto Actuation, Revision 5, the B EDG inadvertently started, when an engineer opened a PT cabinet on the F 4160 switchgear. Operations confirmed that the EDG responded as designed.

Step 7.4.2.6 of the procedure instructed that the PT fuse knife switches be verified to be in the closed position. Due to the engineer not being familiar with the appearance of the knife switches and their location, difficulty was encountered locating them. When the knife switch was not immediately found, the engineer opened the PT fuse cabinet door. This resulted in the PT fuses becoming disconnected causing a sensed undervoltage condition on the 4160 bus and EDG start. The opening of the PT fuse cabinet door was not specified in the procedure.

As immediate corrective action, pictures of the F 4160 switchgear were taken to be used in a training session provided to the engineering staff to identify the appearance and location of the switches. The engineer involved in the mistake participated in the training session. As a long term corrective action, the PT fuse compartment will be labelled, cautioning personnel about the consequences of improperly opening the compartment. Engineering and training personnel plan to evaluate training needs and requirements for engineering staff members.

The inspectors concluded, for the first example, that engineering inattention to details in the use of procedures resulted in inadvertent start of the EDGs. Performing steps not specified in the procedure and a lack of detailed component or system knowledge and response contributed to the second ESF actuation. These failures to follow procedures constitute a violation of minor significance and is being treated as a NCV, consistent with Section IV of the NRC Enforcement Policy. This is identified as NCV 50-366/95-23-03, Inadvertent ESF Actuations During Testing.

e. Review of Unit 1 and Unit 2 Spent Fuel Pool Cooling

The inspectors reviewed the adequacy of the original heat load design assumptions for the Spent Fuel Pool Systems relative to the current operating practice. The inspectors reviewed Unit 2 FSAR section 9.1.3 and Unit 1 FSAR section 10.4 for the Spent Fuel Pool Cooling and Cleanup System and applicable system operating procedures.

Design Basis

The FSAR design basis for Hatch FPC systems are to maintain the fuel pool operating temperature below 139°F during Normal operating conditions, below 133°F during refueling conditions, and below 150°F during core off-load conditions.

Both units identified and used three different conditions and assumptions for heat removal capacity evaluations.

(1) Normal Condition

The heat load analysis for the normal operating conditions assumed that there were 22 batches (assuming one-forth core yearly off-loads) in the pool that had decayed from 1 to 22 years, and the latest batch decayed for 30 days. A single spent-fuel pool cooling system train was used for the decay removal. The analysis showed the heat load was 7.24 MBtu/h. and bulk pool temperature was at or below 139 °F.

(2) Refueling Condition

The assumptions for the refueling mode analysis were the same as those for the normal mode, except the latest batch was assumed to have decayed for only 150 hours, and two spent-fuel pool cooling trains were in service. The analysis showed the heat load was 11.57 MBtu/h and bulk water temperature at or below 133°F

(3) Maximum Condition

The analysis for the heat load following full-core discharge assumed the pool already had 19 one-fourth core discharges in storage that had decayed from 1 to 19 years. The calculated heat load from the 19 batches was 2.39 MBtu/h. The additional decay heat load at 150 hour after shutdown for full-core off-load was calculated to be 26.3 MBtu/h, for a total heat load at 150 hour after shutdown was 28.69 MBtu/h.

The FSAR indicated a single train of RHR without the assistance of SFP cooling would maintain SFP temperature at or below 145°F. As an alternative to aligning the RHR system to the spent-fuel pool for a full-core off-load, the fuel may be allowed to decay in the reactor vessel until the heat load of the core has decreased to a point where two FPC trains can maintain the SFP temperature at or below 150°F.

FPC Description

The system for Unit 1 includes two pumps, two heat exchangers, and two filter demineralize units. The system may be shared with Unit 2 using a crosstie header from the Unit 2 spent-fuel pool cooling and cleanup system to the Unit 1 skimmer tank header. Unit 2 system includes one pump, one heat exchanger, and one filter-demineralizer unit. Both units have crosstie capability to the RHR system.

Additional cooling can be provided by the DHR system. The DHR system is primarily operated during refueling outages to provide decay heat removal from either Unit 1 or Unit 2 spent fuel pools. Use of the DHR system allows the RHR or FPC system to be taken out of service for inspection, repairs or modifications during outages. The DHR has been sized to handle a heat load of 40 MBtu/h. This is approximately equal to the heat load contributed to the SFP by a full-core off load 24 hours after reactor shut down for refueling. The system is designed to meet the maximum required heat load at day 3 of an outage and keep the SFP temperature below 125°F. Analysis show that the DHR system can maintain the SFP temperature at or below 145°F even with the loss of any single DHR system component.

Refueling Metholodogy

The inspectors observations of refueling activities and discussions with operations and engineering personnel revealed a full core off-load is the common practice. The RHR system is seldom used for SFP cooling. The inspectors review of operations for the last four refueling outages and discussions with engineering and operations personnel did not identify instances where RHR was used for SFP cooling. The inspectors noted that during the current refueling outage that Unit 1 SFP cooling system was crosstied with Unit 2. However, discussions with operations and engineering personnel revealed that it was for water quality and not temperature control. During the last three refueling outages the inspectors monitored the DHR system operation and performance while being used on both Unit 1 and Unit 2. The results were excellent and no equipment problems were identified.

The inspectors conducted a review of Unit 2 SFP temperatures during the current refueling outage. The TS required temperature readings were used to obtain the temperature profile. The temperatures are monitored and recorded each shift by CR operators. The reactor was shutdown on September 23. Defueling began on the 26th and the reactor vessel was completely defueled on October 1. Refueling began on October 24 and was completed on the 28th. On September 23 the SFP temperature was 92°F. The highest temperature observed through October 24 was 99°F.

The inspectors concluded that the licensees refueling metholodogy, with respect to heat load removal capability, was bound by the FSAR analysis. Heat load removal capability was not a concern. Even though the licensee discharged a full-core off-load for refueling conditions, the SFP temperature was maintained well below the temperature of 133°F specified in the FSAR. The DHR system as well as RHR provided excessive capacity for heat removal. However, actual metholodogy for routine refueling activities was not consistent with the FSAR heat removal analysis assumptions. The FSAR assumption for one-forth core off-load for refueling conditions was not consistent with the licensees refueling condition. What the FSAR described as the Maximum heat load condition, was consistent with what the licensee does on a normal routine refueling outage.

One non-cited violation was identified

5. Inspection of Open Items (92700) (92901) (92902) (92903)

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

a. (Closed) IFI 50-321,366/95-14-01: Failure of Unit 2 Valve 2E11-F015B, RHR Loop B Injection Valve. This item was opened due to recurring failures of the LPCI valve. A followup inspection was performed, 50-321,366/95-17. An apparent violation was issued as a result of the inspection, VIO 50-321,366/95-17-01, Failure to Provide Prompt Corrective Action to Preclude MOV Failures. A predecisional enforcement conference was conducted in the Region II office on September 13, 1995, to discuss the apparent violation. Based on the results of the enforcement conference this item is closed.

b. (Closed) LER 50-321/95-02: Trip of RPS Power Supply Results in ESF Actuation

(Closed) LER 50-321/95-03: Trip of RPS Bus Results in ESF Actuation

(Closed) LER 50-321/95-04: Trip of RPS Bus Results in ESF Actuation

These LERs were issued from March 14 to July 17, 1995, to document spurious trips of the 1B RPS MG set. The inspector attended technical meetings, discussed the trips with system engineering and reviewed technical memos. From these reviews and discussions the inspectors concluded the licensee could not initially determine the cause of the trips. Additional analysis by the system engineers and the NSAC staff indicated that the voltage regulator was adjusted by the manufacturer for a system power factor of 0.8. However, the licensee determined that the 1B RPS system has a power factor of 0.6. The voltage regulator was adjusted for a 0.6 power factor and the MG set has not tripped since. Based on the licensee's action these LERs are closed.

c. (Closed) LER 50-321/95-06: HPCI System Inoperable Due to Bound Steam Supply Valve. This LER was issued to document a bound HPCI valve which was caused by a failure to follow maintenance procedures. The occurrence was documented in IR 50-321,366/95-16 and a violation was issued in the report. The valve was repaired and the HPCI system was returned to operable status. Based on the issuance of the violation and the valve repairs this LER is closed.

d. (Closed) VIO 50-321/94-31-01: Inadequate Procedure for Fabricating Rigging Slings During Refuel Floor Activities. A failed sling resulted in a dropped core shroud bolt that punctured the SFP liner. The licensee responded to this violation in correspondence dated March 2, 1995. As part of the corrective actions, the licensee's General Manager prohibited the on-site fabrication of rigging slings for use on the refueling floor. Slings previously fabricated on-site and the tools used for on-site fabrication were tagged to preclude future use. The on-site fabricated slings were disposed of December 1994. Slings currently used are color coded to signify that they have been properly tested and/or inspected. None of these slings were fabricated on-site. The inspectors have not observed the use of any slings that were not properly color coded. Based upon the inspectors review of the licensee's actions, this violation is closed.

e. (Closed) VIO 50-321/94-31-02: Failure to Follow Procedures Regarding Refuel Floor Activities - Multiple Examples. The licensee responded to this violation in correspondence dated March 2, 1995. As part of the corrective actions for the four examples, the licensee installed locked barriers to prevent the transient of personnel through the compartment adjacent to the bottom of the transfer canal when the transfer gates are removed. The inspectors verified the barriers to be in place on several occasions when the gates were removed. The inspectors also verified that procedure 52GM-T24-001-0S, Fuel Transfer Canal Operation was revised to require that the HP foreman be notified to secure, lock and post doors and passageway underneath the transfer canal as Very High Radiation Area, HP Escort, Alarming Monitoring Device and RWP required for Entry (Example 1). The manufacturing of slings on site has been discontinued by direction of the GM and the GM's permission is required if the need should arise in the future to fabricate slings on site. The personnel who failed to mark the rigging slings, perform a proper load test and document the load test could not be disciplined for their errors since they no longer are employed at Plant Hatch (Examples 2 and 3). The foreman who failed to inform his supervisor of the dropped shroud head bolt was counseled and reminded of the requirement to inform supervisory personnel when unusual or unexpected events occur.

Based upon the inspectors' review of the licensee's actions, this violation is closed.

6. Exit Interview

The inspection scope and findings were summarized on November 21, 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 50-321,366/95-23-01	Open	Failure to Follow Procedures While Transferring Diesel Fuel Oil (paragraph 2.f).
URI 50-321,366/95-23-02	Open	Problems with Equipment Operability from the Remote Shutdown Panel (paragraph 2.i).
NCV 50-366/95-23-03	Closed	Inadvertent ESF Actuations During Testing (paragraph 4.d).
IFI 50-321,366/95-14-01	Closed	Failure of Unit 2 Valve 2E11-F015B, RHR Loop B Injection Valve (paragraph 5.a).
LER 50-321/95-02	Closed	Trip of RPS Power Supply Results in ESF Actuation (paragraph 5.b).
LER 50-321/95-03	Closed	Trip of RPS Bus Results in ESF Actuation (paragraph 5.b).
LER 50-321/95-04	Closed	Trip of RPS Bus Results in ESF Actuation (paragraph 5.b).
LER 50-321/95-06	Closed	HPCI System Inoperable Due to Bound Steam Supply Valve (paragraph 5.c).
VIO 50-321/94-31-01	Closed	Inadequate Procedure for Fabricating Rigging Slings During Refuel Floor Activities (paragraph 5.d).
VIO 50-321/94-31-02	Closed	Failure to Follow Procedures Regarding Refuel Floor Activities - Multiple Examples (paragraph 5.e).

7. Acronyms and Abbreviations

AC - Alternating Current
AGM - Assistant General Manager
AIM - Automatic Interrupting Motor
ATWS - Anticipated Transient Without SCRAM
CFR - Code of Federal Regulations
CBO - Control Board Operator
CR - Control Room
CST - Condensate Storage Tank
DCR - Design Change Request
DHR - Decay Heat Removal System.
DW - Drywell
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EHC - Electrical Hydraulic Control
ERT - Event Review Team
ESF - Engineered Safety Feature
°F - Degrees Fahrenheit
FPC - Fuel Pool Cooling
FW - Feedwater
FSAR - Final Safety Analysis Report
GE - General Electric Company
GM - General Manager,
h - Hour
HP - Health Physics
HPCI - High Pressure Coolant Injection
IAW - In Accordance With
I&C - Instrumentation and Controls
ILRT - Integrated Leakage Rate Test
IR - Inspection Report
ISTS - Improved System Technical Specifications
KV - Kilovolt
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LOSP - Loss of Off-Site Power
LPCI - Low Pressure Coolant Injection
LPRM - Local Power Range Monitor
LSFT - Logic System Functional Test
MBtu - Million British Thermal Unit
MCC - Motor Control Center
MG - Motor Generator
MOV - Motor Operated Valve
MR - Maintenance Report
Mrem - Milli-rem
MWO - Maintenance Work Order
NCV - Non-Cited Violation
NPSH - Net Positive Suction Head
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
NSAC - Nuclear Safety and Compliance
PCB - Power Circuit Breaker

PEO - Plant Equipment Operator
PM - Preventive Maintenance
PSW - Plant Service Water System
PT - Potential Transformer
RCIC - Reactor Core Isolation Cooling
RHR - Residual Heat Removal
RHRSW- Residual Heat Removal Service Water
RO - Reactor Operator
RPS - Reactor Protection System
RSDP - Remote Shutdown Panel
RR - Reactor Recirculation
RTP - Rated Thermal Power
RV - Reactor Vessel
RVWL - Reactor Vessel Water Level
RWP - Radiation Work Permit
SBGT - Standby Gas Treatment
SDC - Shutdown Cooling
SF-6 - Sulfur Hexaflouride
SFP - Spent Fuel Pool
SMA - Seismic Margin Analysis
SOR - Significant Occurrence Report
SPDS - Safety Parameter Display System
SR - Surveillance Requirements
SRO - Senior Reactor Operator
SRV - Safety Relief Valve
SS - Shift Supervisor
TS - Technical Specifications
VPI - Valve Position Indication