U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee:	Philadelphia Electric Company Peach Bottom Atomic Power Station P. O. Box 195 Wayne, PA 19087-0195	
Facility Name:	Peach Bottom Atomic Power Station Units 2 and 3	
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Areas Inspected:

The inspection included routine, on-site regular, backshift and deep backshift review of accessible portions of Units 2 and 3. The inspectors reviewed operational safety, radiation protection, physical security, control room activities, licensee events, surveillance testing, engineering and technical support activities, maintenance, and the Unit 3 startup.

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Attachment I

EXECUTIVE SUMMARY

Peach Bottom Atomic Power Station
Inspection Report 91-34

Plant Operations

The inspectors observed that licensee preparations for and conduct of plant pre-startup and startup testing were cautious and thorough. Testing activities were effectively controlled by shift management, and the inspector noted strict procedure adherence by plant personnel.

Near the close of the inspection period, the licensee determined that the Unit 3 primary containment oxygen concentration had exceeded the Technical Specification limit. The control room staff's immediate actions to confirm the indication and to reduce the concentration were well conducted. The licensee promptly initiated an investigation of the event. The results of the licensee's investigation and the corrective actions will be reviewed during a future inspection (Section 3.4, Unresolved Item 91-34-001).

Maintenance

The inspector determined that the station maintenance technicians and engineers responsible for the motor operated valve (MOV) diagnostic test program were well informed regarding industry developments, and knowledgeable of testing techniques. The licensee's approach at Peach Bottom to evaluating emerging industry information regarding MOV diagnostic test equipment accuracy was proactive and focused on assuring safety (Section 5.3).

Engineering and Technical Support

The inspector reviewed two Unit 3 modifications implemented during the outage and concluded that the licensee's development, installation and testing of the modifications were thorough and well implemented. The inspector did identify weaknesses in log keeping and communications during testing, and in the turnover and tagging process which were reviewed and corrected by the licensee (Sections 5.1 and 5.2).

The inspector identified two examples of changes to procedures that were not appropriately processed by the technical staff. The changes were minor and effected testing of nonsafety-related equipment only. Other changes to safety-related procedures reviewed by the inspector were implemented correctly (Sections 5.1 and 6.0).

Assurance of Quality

The NRC and the licensee continued their evaluations of the automatic depressurization system (ADS) solenoid operated valves (SOV) thermal degradation begun during last inspection period. As noted in Inspection Report 91-33, the licensee's corrective actions following discovery of the degradation were not adequate in that they did not identify a similar problem on Unit 2. During this inspection period, the licensee conducted a well organized, thorough and in-depth investigation of these problems. The staff assigned to conduct the review was trained in root cause analysis techniques, and applied them effectively. Licensee management maintained oversight of the investigation and clearly stressed the need to consider the generic implications (Section 4.0).

DETAILS

1.0 PLANT OPERATIONS REVIEW (71707)[1]

The inspector completed NRC Inspection Procedure 71707, "Operational Safety Verification," by directly observing safety significant activities and equipment, touring the facility, and interviewing and discussing items with licensee personnel. The inspector independently verified safety system status and Technical Specification (TS) Limiting Conditions for Operation (LCO), reviewed corrective actions, and examined facility records and logs. The inspectors performed 12 hours of deep backshift and weekend tours of the facility.

The inspector observed that licensee management and staff response to plant events and equipment problems occurring during the period continued to be prompt and reflected a sound safety perspective. Control room operators and supervision generally maintained good oversight of activities, and reacted effectively to plant transients.

During the report period the inspectors routinely assessed the plant physical condition and housekeeping. Generally housekeeping was good. Particularly noteworthy was the condition of the main working elevations in the Unit 2 reactor building. However, the inspector observed that the conditions of some lower elevation pump rooms was poor. For example, on January 15 and 16, during a tour of the four Unit 2 residual heat removal (RHR) pump rooms the inspector noted several housekeeping deficiencies. These deficiencies included ladders not secured in their storage locations, poor lighting, a scaffold in contact with the suction piping to a RHR pump, and storage of scaffolding material near safety grade instrumentation. In addition, the inspectors noted that top half of the 'B' RHR pump was not insulated.

The inspectors informed licensee management of each observation. The scaffold was corrected to eliminate the contact with the pump suction piping. The work order building the scaffold had not been completed, and final inspections had not been completed at the time of the inspector's observation.

The Nuclear Engineering Department initiated a review of the additional heat load due to the partially insulated RHR pump, to determine how this condition would affect the room coolers. Preliminary results reviewed by the inspector indicated that the effect was insignificant. The licensee is currently evaluating plant insulation control as discussed in Section 4.0. The licensee also initiated actions to resolve the other housekeeping concerns.

The inspectors concluded that generally housekeeping was good, however, additional attention in some areas is needed.

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[1]The inspection procedure from NRC Manual Chapter 2515 that the inspectors used as guidance is parenthetically listed for each report section.

2.0 UNIT 3 STARTUP FROM REFUELING (71707, 71711)

The inspectors observed licensee preparations for and conduct of plant pre-startup and startup testing during the inspection period. Licensee conduct of these activities were cautious and well controlled.

2.1 Unit 3 Containment Integrated Leak Rate Test

The licensee conducted a periodic Containment Integrated Leak Rate Test (CILRT) at Peach Bottom Unit 3 from December 21-23, 1991. The licensee is committed to perform the CILRT in accordance with ANSI/N45.4 1972 "American National Standard Leakage-rate Testing of Containment Structures for Nuclear Reactors." The test was performed in accordance with surveillance test procedure ST-T-07A-600-3, "Integrated Leak Rate Test."

The purpose of this inspection was to ascertain whether the CILRT was conducted in compliance with the NRC requirements and if the test results satisfied the acceptance criteria specified in the station procedure. The inspector reviewed the CILRT procedure, the CILRT test log, instrumentation calibration records, test data and results. The inspector observed portions of the CILRT, including the leakage verification test, and interviewed responsible test personnel. Through review of the CILRT procedures and discussions with the test directors the inspector verified that:

- The Test Director's responsibilities were clearly defined,
- The procedures were adequately detailed to assure satisfactory performance of the CILRT,
- All test prerequisites were satisfied,
- All systems required to maintain the plant in a safe condition during the test were operable, and
- The procedure addressed liquid level changes during the CILRT, and the actual calculations or graphs were presented.

The inspector noted that the test procedure did not have a requirement to verify the vacuum-release device operability as required by ANSI/N45.4 1972, Section 4.6, "General Preparations for Test Pressurizing." However, the inspector verified that the devices had been tested during October 1991. The licensee stated that this verification requirement would be added as a prerequisites to the test procedure before the next CILRT. The procedure was otherwise well written and sufficiently detailed to assure control of the test activities.

The inspector toured the control room and reactor building to verify that the test activities were conducted in accordance with the test procedure. The inspector surveyed test boundaries for evidence of leakage, and to verify valve positions. During the test, the licensee identified two valve position errors.

- During preparation for the CILRT, the licensee observed that the reactor vessel water level was decreasing at about 1 1/2 inches/hour. The licensee identified that this decrease was caused by leaks through the high pressure service water to residual heat removal (RHR) system cross tie valves A0-3-10-174 and CHK-3-10-177. Downstream drain valve A0-3-10-173 was open and created a water drain path. The inspector noted that this reactor water inventory reduction would have no impact on the containment integrity during an accident because this leakage path would not be open to the containment atmosphere. Water would be present in this line throughout the course of a design basis accident. The licensee agreed to discuss this observation in the CILRT report to the NRC.

- The licensee also observed that RHR test valve HV-3-10-31570A, and control rod drive exhaust filter valve HV-3-3-31665B were open, while the test configuration required them to be closed. The licensee immediately returned these valves to the closed position.

Neither of these valve line-up errors negatively impacted the CILRT. The licensee initiated event investigations for each of the valve mispositions.

An independent calculation of the CILRT leak rate utilizing an NRC computer program verified that the measured leak rate met the acceptance criteria. A detailed evaluation of the data will be performed when the licensee's final results report is submitted. The licensee's analysis of the results indicated an acceptable as-left CILRT. Utilizing as-found and local (type C) leakage, the licensee preliminarily determined that the containment met the test acceptance criteria in the as-found condition.

The inspector concluded that the licensee's planning and conduct of the CILRT were effective. While several minor valve alignment errors were identified by the licensee, these errors did not affect test validity and were promptly documented and corrected.

2.2 Startup Testing Activities

The inspectors observed plant startup activities, reviewed procedures, and interviewed personnel involved with the activities. Startup operations, post-critical tests, and other surveillance tests were reviewed and observed. The tests observed and/or reviewed are listed in Attachment I. The inspector reviewed the procedures to determine if they provided appropriate instructions, precautions, limitations and acceptance criteria and were in conformance with the requirements of the Technical Specifications and Updated Final Safety Analysis. Methods and calculations were reviewed to determine if they were clearly specified and performed. The inspector determined that the test program was well conducted and was controlled by shift management. The inspector observed strict adherence by plant personnel to procedures and test schedules.

The inspector observed that test personnel appropriately documented and dispositioned discrepancies. For example, during a reactor core isolation cooling system test, pump discharge pressure at the required flow rate was found to be lower than specified, 80 versus 100 Pounds per square inch gauge (psig) above reactor pressure. The test was determined to be unsatisfactory. The test engineer collected additional data at various pump flows and discharge pressures. After evaluation of this information and review of the engineering calculation establishing the value, the engineer initiated a temporary procedure change, which was reviewed and approved by the Plant Operation Review Committee (PORC). The inspector reviewed the calculations and found the change to be acceptable. Other tests observed by the inspector were conducted in accordance with procedures and the results were appropriately reviewed and approved. The inspector had no further questions.

3.0 FOLLOW-UP OF PLANT EVENTS (93702, 71707)

During the report period, the inspector evaluated licensee staff and management response to plant events to verify that the licensee had identified the root causes, implemented appropriate corrective actions, and made the required notifications. Events occurring during the period are discussed individually below.

3.1 Unit 3 Primary Containment Group I Isolation During Instrument Line-up

At about 10:00 p.m. on December 16, 1991, an unexpected primary containment isolation system (PCIS) actuation occurred, when an auxiliary operator (AO) valved main steam line high flow transmitter FT 3-06-051D into service. The instrument had been out of service and had not yet been backfilled. The reactor vessel hydrostatic pressure test was in progress, with reactor coolant system at a pressure of 1000 psig and at 199 degrees Fahrenheit (F). Both the outboard and inboard main steam isolation valves were already closed to support the test. When the actuation occurred the main steam drain and recirculation sample isolation valves closed as expected.

The Nuclear Engineering and Services Department had replaced isolation valves on the sensing line to FT 3-06-051D, and were preparing to perform an in-service leak test per procedure IP-11.1, "Procedure For the Pressure Testing of Piping." The Outage Shift Coordinator (OSC) assigned an AO to oversee the testing. In addition, the OSC requested support from the Instrument and Control (I&C) Group to open the instrument valves under direction from the AO. The AO did not wait for the I&C technician to arrive and valved in the instrument, resulting in the PCIS actuation. The licensee informed the NRC of the event via the Emergency Notification System (ENS).

The inspector reviewed the licensee's immediate corrective actions, LER 91-018, the event investigation report, relevant procedures and interviewed the personnel involved in the event. The licensee concluded that the AO was not aware that the standard practice was to have I&C technicians valve in instruments. The AO training and the Operations Management Manual (OMM) did not address this practice. The OSC did not instruct the AO that the I&C technician should manipulate the valve. Also IP-11.1 did not contain precautions or instructions pertaining to instrument line backfill and isolation valve manipulations.

The licensee briefed all AOs on expectations concerning manipulation of instrument isolation valves. The licensee's planned long-term corrective actions include defining AO duties and responsibilities for instrument valve manipulation in the OMM, and revision of IP-11.1 to improve guidance for this type of in-service leak testing. The inspector concluded that the licensee's analysis was thorough and the proposed corrective actions were appropriate.

3.2 Unit 3 Shutdown Cooling Isolation

On December 18, 1991, a shutdown cooling (SDC) isolation occurred when a PCIS logic fuse blew. The licensee had just completed the reactor vessel hydrostatic pressure test, and had placed shutdown cooling in service. The reactor operator maximized reactor water cleanup system and the control rod drive flows for cooling. The coolant temperature decreased approximately 3 degree F per hour, until the SDC was restored about eight hours later. The licensee informed the NRC of the SDC isolation via the ENS.

The cause of the blown fuse was traced to a shorted coil in relay 16K-K50, a General Electric Company (GE) type CR120 relay. The licensee replaced the relay, and initiated an evaluation of the event. All normally energized CR120 relays are on a 6 year replacement schedule. The SDC relays are normally deenergized because SDC is used only intermittently. However, during the extended plant outages from March 1987 to December 1989, SDC service time were much higher than normal and the replacement schedule was not accelerated to compensate. The licensee will revise the preventive maintenance program to address the remaining SDC relays. The inspector reviewed the immediate corrective actions, the event report, LER 91-019 and discussed the event with the system engineer and maintenance personnel. The inspector determined that the licensee's planned corrective actions were adequate. The inspector had no further questions.

3.3 Unit 3 Reactor Core Isolation Cooling System Torus Suction Valve Fuse Failure

On January 4, 1992, the licensee determined that containment integrity could not be assured for the reactor core isolation cooling (RCIC) suppression pool suction line. During performance of a RCIC logic surveillance test an indicating light socket shorted to ground and a fuse blew, deenergizing portions of the RCIC logic. This caused both the inboard and outboard isolation valves, MO-3-13-39 and MO-3-13-41, in the RCIC suppression pool suction line, to open. Due to the logic configuration, the valves could not be closed and maintained closed. The licensee informed the NRC of the potential loss of containment integrity via the ENS.

The loss of logic power to relay 13A-K55, condensate storage tank (CST) low level, generated a RCIC suction source automatic transfer signal and opened the suppression pool suction valves. The relays that provide the automatic isolation signal to these valves, 13A-K12 and 13A-K54, were also deenergized. Since the isolation logic for these valves is energize to actuate, the function was disabled. The valves could not be maintained closed manually from the control room hand switch due to the sealed-in CST low level signal. The licensee electrically deactivated and closed one valve to isolate the penetration. Also, the licensee declared RCIC inoperable, since the RCIC initiation logic was affected.

The licensee replaced the faulty socket and fuse, and the technical staff initiated an evaluation of the logic and containment isolation design to determine if the failure of one fuse causing two valves to fail open was acceptable. The preliminary result of this evaluation was that these valves are not considered as automatic primary containment isolation valves, and that only valve MO-13-041 is a manual containment isolation valve. Based on these conclusions, the licensee stated that the current design is acceptable. A final engineering disposition will be issued in response to Engineering Work Request A0360092. The system engineer prepared a memorandum to all licensed operators explaining the event. The inspector had no further questions at this time.

3.4 High Oxygen Concentration In the Unit 3 Containment During Power Operation

On January 17, 1992, at about 5:40 p.m., the Unit 3 control room annunciator for high primary containment oxygen concentration alarmed. The reactor operator (RO) noted that the oxygen concentration indicator in the control room was erratic, and indicated as high as 8 %. The Shift Manager (SM) directed the RO to place the containment atmospheric dilution (CAD) system analyzers in service to monitor oxygen concentration. The CAD analyzers require a four hour warm-up before use. The SM also directed chemistry to obtain and analyze a sample of the containment atmosphere. At about 9:45 p.m. the in-service CAD analyzers and the results of the atmosphere sample indicated concentrations of about 7.8 %. The Technical Specifications (TS) require that primary containment oxygen concentration be maintained below 4 % with the unit in the run mode. The purpose of this limit is to preclude the creation of an explosive hydrogen-oxygen mixture following a design basis accident. If this limit cannot be met, the plant must be placed in cold shutdown within 24 hours. The licensee initiated a plant shutdown at 9:50 p.m. on January 17, and later informed the NRC of the event via ENS. The licensee performed containment inerting activities in parallel with the plant shutdown. By about 7:00 a.m. on January 18, 1992, the licensee had reduced primary containment oxygen concentration to less than 4 %, and terminated the plant shutdown.

The inspector reviewed the actions taken by the control room staff in response to the erratic oxygen concentration indication. The SM initiated prudent actions to evaluate the actual concentration. After confirming that the concentration had exceeded the TS limit, the SM promptly initiated a plant shutdown and the containment inerting procedure. The inspector observed the operators performing the containment inerting activities after confirmation of the high oxygen concentration. The RO and Shift Supervisor were knowledgeable of the precautions and constraints applicable to the evolution, and reviewed and effectively used the relevant procedures. The inspector concluded that the licensee's immediate response to this event was appropriate. The licensee is conducting an investigation to determine the factors contributing to this violation of TS. Because the event occurred near the close of the inspection period, the licensee had not completed their investigation. This item will remain unresolved pending completion of the investigation and additional review by the inspector (UNR 91-34-001).

4.0 FOLLOW-UP OF IMPROPERLY INSTALLED AUTOMATIC DEPRESSURIZATION SYSTEM INSULATION (40500, 71707)

Following removal of three safety relief valves (SRV) from the drywell for periodic surveillance testing in September 1991, the licensee identified that the solenoid operated valves (SOVs), splices and cables showed signs of significant thermal degradation. The licensee also found that the thermal insulation on the remaining eight SRVs was installed improperly, resulting in local area temperatures of about 434 degrees F. The licensee concluded that the automatic depressurization system (ADS) on Unit 3 had been inoperable for most of the 21 month operating cycle due to rapid thermal aging. As part of their immediate corrective action, the licensee performed a walkdown of the Unit 2 SRVs and concluded that all insulation was properly installed. Subsequently, the NRC Resident Inspector performed a walkdown and identified that the Unit 2 'C' SRV insulation was not properly installed. These events were previously described in NRC Inspection Report 91-33, Section 2.1. During the current inspection period additional information became available regarding the licensee's component functional testing results, event investigation findings and planned corrective actions. This information was reviewed by the inspector and NRC management during the period, and was discussed during an Enforcement Conference in Region I. The results of these efforts are summarized in the following sections.

4.1 Licensee Investigation Results

The licensee established an event investigation team to evaluate the problems, identify causal factors and root causes, and propose short and long-term corrective actions. The inspector monitored the ongoing investigation to assess the scope and depth of the review, and the validity of the proposed corrective actions. With respect to the Unit 3 problem, the licensee identified the following contributing factors:

- Inadequate maintenance planning. The package provided to the contractor for installing the insulation did not contain adequate procedures or drawings.
- Inadequate post-maintenance inspection. Several maintenance request forms (MRF) were involved. Each MRF referenced another for completion of the inspection. Also the work package lacked sufficient details to support an effective inspection..
- Inattention to detail in performing post-modification inspections. A special procedure (SP) for inspection of the insulation, containing adequate instructions, had been completed. However, it was not properly implemented in that the SRV configuration was not compared to the drawings.

- Poor follow-up to concerns raised by a maintenance technician during the Unit 3 mid-cycle outage. In November 1990, a maintenance technician questioned if the insulation had been modified, because it was not installed consistent with his previous experience. The licensee did not perform aggressive follow-up.

The licensee's investigation of the improperly insulated Unit 2 SRV, and their failure to identify it, indicated the following weaknesses:

- Inadequate planning and control of the inspection of the Unit 2 equipment following identification of the Unit 3 problem. The maintenance engineer who performed the inspection was not provided with a checklist, drawings or engineering specifications.
- The insulation on all 11 valves had been altered by a contractor during a refueling outage in 1988 without processing a modification. The changes to the insulation on ten of the 11 SRVs had no significant effect. On the 'C' SRV the change could have adversely impacted the components.

The licensee's investigation was well organized, thorough and in-depth. The staff assigned to conduct the review was trained in root cause analysis techniques, and applied them effectively. Licensee management maintained oversight of the investigation and clearly stressed the need to consider the generic implications. In response to the issues identified, the licensee implemented a series of specific and broad corrective actions. These actions included:

- Initiation of engineering reviews of critical insulation applications.
- Revision of maintenance procedures and the planning database to incorporate the information obtained through the engineering reviews.
- Conduct of in-plant walkdowns of high temperature piping to identify any additional installation errors.
- Discussion of the event with maintenance foreman, planners and engineers to improve sensitivity to the potential impact of improper insulation.
- Revision of maintenance planner training to include information on critical insulation.
- Discussions with the plant staff to emphasize the need for attention-to detail and aggressive follow-up of abnormal conditions.

The effectiveness of these corrective actions will be evaluated during a future inspection.

4.2 Component Testing Approach

The licensee performed a series of tests on the damaged SOVs to determine their ability to function under worst case conditions. There are 11 SRVs on each unit; each equipped with one ASCO SOV and its associated splice and cable. The SOVs associated with the Unit 3 'B' ADS valve and the 'J' and 'L' SRVs were inadvertently thrown away after their removal from the drywell. Licensee physical inspection of the SOVs before they were thrown away identified significant deterioration. The licensee divided the remaining eight Unit 3 SOVs into two groups, with two ADS and two SRV valves in each group. The groups underwent the following testing:

- Functional Test

  All eight valves underwent initial functional testing that consisted of energizing the solenoid and verifying that adequate pressure was ported to the cylinder.

- Accident Test 1 (ADS valves 'A' and 'C'; SRV valves 'D' and 'E')

  The valves were heated to 434 degrees F. The heat-up was followed by simulation of the steam environment expected following an intermediate break loss of coolant accident (LOCA) inside containment. After ten minutes in this environment, each valve was energized and remained energized for two hours. The valves underwent one vibration operation test. This consisted of energizing each valve and subjecting it to a shock in the plane of the coil and plunger, while monitoring the cylinder port for pressure drop.

- Accident Test 2 (ADS valves 'G' and 'K'; SRV valves 'F' and 'H')

  The valves were heated to 434 degrees F. The temperature of the test chamber was then reduced at a rate of about 100 degrees per hour for the duration of the 159 minute test. This decreasing temperature profile is characteristic of an intermediate break LOCA outside containment. The test did not subject the components to a steam environment. The valves were energized five times for three minutes periodically during the cool - down. Each valve underwent five vibration operation tests as described in Accident Test 1.

The licensee believes that Accident Tests 1 and 2 were equally challenging, and that a successful result in either test is valid evidence that the valve would have functioned.

All valves had been partially disassembled and reassembled before shipment to the test facility. The 'A' and 'C' ADS valves exhibited leakage when first energized for the functional test and were adjusted. Also, the splices and cables were not included in the test setup for all SOVs. The licensee does not believe that these factors impacted the validity of the test. The 'A' ADS valve operated properly during the accident testing. The 'G' ADS valve operated properly once during its test. The 'D', 'F' and 'H' SRVs operated properly during their accident testing. The 'C' and 'K' ADS valves, and 'E' SRV did not function properly. In summary, the licensee concluded that two ADS valves, the 'A' and 'G', would have functioned to mitigate an accident. The licensee also tested the Unit 2 'C' ADS valve and determined that it would have functioned if called upon.

4.3 Safety Assessment

Using the results of the testing program described above the licensee performed an evaluation of the potential impact of the equipment degradation on design basis events. The inspector reviewed the TS, the Updated Final Safety Analysis Report (UFSAR) and GE analyses to assess the potential safety significance. This assessment is described below.

4.3.1 System Safety Design Basis

The core standby cooling systems (CSCS) at Peach Bottom include the low pressure coolant injection system (LPCI), core spray system (CS), high pressure coolant injection system (HPCI) and the ADS. Three of the safety design bases for the CSCS relevant in considering the subject event are:

- To provide adequate cooling of the reactor core under abnormal and accident conditions, various cooling systems are provided with diversity, reliability, and redundancy such that inadequate cooling of the core is highly improbable.

- The physical effects of the design basis LOCA do not prevent the CSCS's from effectively cooling the core. These effects are missiles, fluid jets, high temperature, pressure, radiation, and humidity.

- No single failure, maintenance, calibration, or test operation prevents the integrated operation of the CSCS's from providing adequate core cooling.

The UFSAR identifies two types of events requiring pneumatic operation of the SRVs; 1) LOCAs that do not result in depressurization of the primary coolant system through the break, and 2) alternate safe shutdown of the plants in the event of a fire.

For the Unit 2 problem, only one ADS valve was effected. This does not substantially impact the ability of the plant to cope with events. In addition, licensee testing of the valve after removal demonstrated that it would have operated.

Given that all eleven Unit 3 SRVs were effected, a significant degradation in plant capabilities existed. Considering the safety design bases listed above, the impact of degraded SRV electrical components on each type of event for Unit 3 is discussed.

4.3.2 Loss of Coolant Accidents

The CSCS are designed to cope with the spectrum of potential LOCAs. For large breaks, the LPCI and CS are adequate to provide single failure proof accident mitigation; ADS is not required. For intermediate and small break LOCAs, HPCI is capable of maintaining adequate core cooling. In the event that HPCI is unavailable, the ADS acts to depressurize the reactor so that either LPCI or CS can be used for inventory makeup. The ADS, in conjunction with a low pressure CSCS, is functionally redundant to HPCI.

The TS requires five operable ADS valves for continued operation. The Plant Nuclear Safety Operational Analyses contained in Appendix G of the UFSAR requires four ADS valves to satisfy the nuclear safety operational criteria. The GE analysis documented in NEDO-24708A used a less conservative (more realistic) approach, and concluded that three ADS valves would be required. This GE analysis was used to support the Emergency Procedure Guidelines. The licensee has indicated that analyses done in support of the probabalistic risk assessment indicate that only two valves would be needed.

Due to the rapid thermal aging of the SOVs, cables and splices, the qualification of these components lapsed shortly after the plant restart in December 1989. The thermal aging resulted in degradation of all the valves, and several clear failures. If all valves are considered inoperable due to the loss of qualification, then no ADS valves (or SRVs) were available to mitigate a LOCA. In this case, the failure of HPCI would result in an unacceptable safety result. HPCI was nonfunctional for about 510 hours during the operating cycle.

As previously discussed the licensee's testing indicated that the 'A' ADS valve would have functioned. The 'G' ADS valve also operated, but only on the first attempt. With only two ADS valves functional, adequate equipment was not available to meet the minimum requirements specified in the licensing basis or in the GE analysis for coping with the limiting intermediate break LOCA. The licensee believes, however, that based on additional realistic analyses the operation of two ADS valves would be sufficient to mitigate an event.

4.3.3 Alternate Shutdown (Appendix R)

The Fire Protection Plan describes the methods to achieve safe shutdown in the event of a significant fire. The licensee established safe shutdown method D for fires in the control room, cable spreading room, computer room or the emergency shutdown panel area. Safe shutdown method D requires operation of two SRVs. Valves 'A', 'B', and 'K' are controllable from the ADS alternate control station. Valve 'B' was found damaged and disposed of without testing, and must be considered unavailable. Valve 'K' failed to operate during testing. Therefore, only valve 'A' remained functional. This does not meet the minimum of two required and the plant was not in compliance with Appendix R. The licensee evaluated the impact of this condition on core melt frequency, and concluded that the impact was small.

4.3.4 Assessment Summary

During the operating cycle no events involving elevated reactor coolant system leakage rates occurred. In addition, there were no events requiring manual or automatic operation of any SRVs. The pressure relief function of the SRVs was not significantly affected. Although not an engineered safety feature, the reactor core isolation cooling system was operable during those periods when HPCI was unavailable.

Peach Bottom Unit 3 operated for about 21 months with ADS and other SRV electrical components in an unqualified condition. Also during the cycle, HPCI, a redundant system to ADS, was non-functional for about 510 hours. These conditions placed the plant in a degraded condition, and raised concern about the ability to cope with the spectrum of accidents and events. The licensee has stated that additional analyses, beyond that described in the UFSAR, indicates that the remaining functional ADS components were still capable of mitigating the LOCA, and a fire.

4.4 Enforcement Conference

On January 17, 1992, the NRC held an Enforcement Conference with licensee management to discuss the events and their follow-up actions. The licensee's presentation was informative and provided valuable information. The final NRC decision regarding the appropriate enforcement action will be transmitted via separate correspondence.

5.0 ENGINEERING AND TECHNICAL SUPPORT (37700, 71707)

The inspectors routinely monitor and assess licensee support staff activities. During this inspection period, the technical adequacy of two modifications and licensee activities involving the testing of motor operated valves were reviewed. The results of these reviews are discussed in detail below.

5.1 Digital Feedwater Control System Modification

During the recent Unit 3 refueling outage, the licensee replaced the existing analog feedwater control system with a digital feedwater control system (DFCS). The principal objectives for replacement of the existing feedwater control system were to solve the obsolescence problem of the GEMAC analog hardware, improve reliability and maintainability through fault tolerance, and improve vessel level control following reactor scrams using a setpoint setdown feature. The licensee developed and implemented Modification (MOD) 1843, "Replacement Feedwater Control System." The licensee decided not to enable the setpoint setdown feature of the new DFCS for Unit 3 until implementation of the modification for Unit 2. This will maintain operator response to reactor scrams on both units the same.

During this inspection period, the inspector reviewed the modification package for MOD 1843, including the Design Input Document (DID), Safety Evaluation, and several Modification Acceptance Tests (MAT). The inspector discussed the modification in detail with the responsible site and Nuclear Engineering Division (NED) system engineers and attended portions of the classroom and simulator training for the modification. The inspector reviewed the acceptance criteria for the MATs described in the DID and compared these to GE acceptance criteria normally used during startup testing of feedwater control systems. The inspector noted that the licensee had met with representatives of GE in December 1991 to review their plans for testing of the DFCS. The inspector witnessed ongoing testing of the DFCS at various power levels.

Based upon this review, the inspector found that the licensee had thoroughly developed and implemented MOD 1843, and that the licensee's post-modification test plan was thorough. The inspector found testing to be conducted in a well controlled and professional manner, except as discussed below.

On January 3, 1992, during conduct of MAT 1843F which demonstrated the ability of level controller LIC-9091 to maintain the reactor level setpoint during startup, the inspector noted that the system engineer had implemented a Temporary Change (TC) to allow for a more rapid change in the LIC-9091 setpoint. The TC addressed this setpoint change for only one (DCC-X) of the two DFCS computers. However, the inspector observed that the engineers performing the test had also changed the other DFCS computer (DCC-Y). During the restoration steps of the procedure, the engineers appropriately restored the applicable set points to their original values for both computers. The inspector questioned the system engineer regarding the need to include the change to the second computer in the TC. During subsequent testing, the inspector verified that an appropriate TC had been implemented to control the change in computer point values for both computers. Licensee management acknowledged the inspectors concern and reviewed the requirements for the implementation of TCs with their personnel.

On January 14, the system engineers performed MAT 1843H which tested the DFCS response to a small master level controller setpoint step change at 50% reactor power. During the test, the 'C' reactor feedpump responded properly to a positive level step change of six inches while the 'A' feedpump did not respond properly. During review of the RO log for January 14, the inspector noted that the RO had experienced difficulty bringing a second feedpump on at 50% power. A reactor water level transient resulted and water level decreased to within six inches of the scram point. The inspector noted that this water level transient occurred prior to the performance of MAT 1843H discussed above. No DFCS testing was being conducted at the time of the water level transient. The inspector noted that the RO log did not identify that any DFCS testing had occurred, and that operations had not written an event investigation form (EIF) for the level transient. Upon discussion with operations personnel the inspector noted that there was a misunderstanding among the shift as to what had caused the level transient. Operators believed that conduct of the DFCS testing had contributed to the level transient. The lack of clear control room logs contributed to this misunderstanding. The inspector discussed the log keeping weakness and failure to initiate an EIF with operations management. The Shift Operations Manager later discussed log keeping and communications expectations with the Shift Managers. Subsequent to this event, the inspector noted improved log keeping by the ROs and improved communication between the system engineers and the shift regarding conduct of the DFCS testing. In addition, an EIF was initiated on January 16, to appropriately investigate the level transient event. Preliminary licensee investigation found that a DFCS computer software deficiency caused the failure of the 'A' feedwater to respond during testing, and contributed to the level transient. The NED system engineer initiated an Engineering Review Request Form and appropriate changes to the DFCS software were implemented.

The inspector reviewed a sample of about 27 documents to verify that they had been revised to incorporate changes resulting from the modification prior to the turnover to operations. The inspector noted that two system operating procedures, SO 6C.1.B-3 and SO 6D.2.C-3, which involve use of level controller LIC-3558, had not been revised as of January 16. The modification engineer stated that since the procedures had not been revised, LIC-3558 had been treated as a turnover exception in the partial modification turnover accepted by operations on December 31, 1991. The modification engineer stated that LIC-3558 was to be administratively tagged-out until the revised supporting documents were placed in the control room, as described in the Operator's Manual (OM)-10, "Equipment Control." LIC-3558 is currently not used by the ROs for controlling level during reactor startups. Upon further review, the inspector found that the administrative tag-out of LIC-3558, had not been applied by operations. In addition, the inspector identified that a tag from clearance 91001169 was still applied to the instrument air block valve (HV-3-36B-56111) to the control valve (CV-3-6-3558) for LIC-3558. The clearance had been removed and closed out on November 14, 1991. The inspector discussed these issues with licensee personnel including operations management. The Shift Operations Manager stated that the failure to apply the administrative tag-out was an isolated incident, since no other modifications were partially turned over to operations during this outage. Management stated that a task force has been reviewing the modification process and future changes to the process will strengthen this aspect. The licensee properly applied the administrative tag-out of LIC-3558 on January 27 and initiated an EIF on January 25, to investigate the failure to remove the tag applied to HV-3-36B-56111. The inspector had no further questions.

5.2 Installation of Alternate Power Feeds for Battery Chargers and 120 Volt AC Distribution Panels

The AC and DC electrical distribution systems at Units 2 and 3 are crosstied. Some common and Unit 2 loads are supplied from Unit 3, and some common and Unit 3 loads are supplied from Unit 2. When one of the units is in a refueling outage the licensee performs various preventive and corrective maintenance tasks, and surveillance testing on safety-related electrical distribution components. In some cases, the tasks being performed on the shutdown unit effect the operability of systems on the operating unit due to these crossties. As a result, the operating unit is forced into one or more stringent TS action statements. To facilitate the performance of maintenance and testing while minimizing the impact on operating unit equipment, the licensee developed and implemented Modification 5209, "Installation of Alternate Power Feeds for Battery Chargers and 120 Volt AC Distribution Panels."

During this report period the inspector reviewed the modification package for Unit 3, supporting analyses, post-modification acceptance tests, and operating procedure revisions to assess the technical adequacy of the modification and its implementation. In-process controls applied during installation of the modification were reviewed to verify that the impact on the operating unit was assessed, controlled and minimized. The inspector also walked down the completed modification with the responsible station engineering personnel to inspect the quality and completeness of the installation. Based on this review the inspector concluded that the development, installation and testing of the modification had been through and well implemented.

The safety evaluation (SE) supporting the modification requires that crossties be restricted to outage periods, one electrical division at a time, and for certain crossties buss loading restrictions must be implemented. The SE also recognizes that when using a crosstie, the safe shutdown capability (SSC) required by Appendix R for certain plant fire areas would be lost. The SE states that this is acceptable for the short duration involved, provided compensatory fire watches are posted in the effected areas. The licensee interprets NRC Generic Letter (GL) 86-10, "Implementation of Fire Protection Requirements," as allowing the short-term use of compensatory measures in this manner during performance of maintenance. The inspector reviewed the Unit 3 Abnormal Operating Procedures used to control operation of the crossties to verify that the restrictions on their use and an initiation of fire watches established in the SE had been appropriately incorporated. No discrepancies were identified. The inspector discussed this interpretation with NRC Region I and headquarters engineers cognizant of Appendix R requirements. Based on the discussions the inspector questioned if the use of the crossties and resultant effect on SSC was allowed by Appendix R and was consistent with the GL. The licensee agreed to provide information concerning the basis for their conclusion. This item will remain unresolved pending completion of additional NRC review (UNR 91-34-002).

5.3 Motor Operated Valve Testing Activities

During the refueling outage the inspector monitored the licensee's performance of motor operated valve (MOV) diagnostic testing, evaluated the results, and compared them with the MOV thrust requirements provided by the licensee's engineering organization. The objective of this inspection was to assess the approach applied by the plant staff in setting up and testing MOVs, the level of staff knowledge with respect to contemporary MOV industry experience and their analysis and disposition of test data.

The NRC issued Bulletin 85-03, "Motor Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings," and NRC Generic Letter 89-10, "Safety-Related Motor Operated Valve Testing and Surveillance," requesting that licensees perform the analyses and testing necessary to ensure that safety-related motor operated valves (MOVs) are capable of functioning to mitigate design basis events. In response to these requests, the licensee had implemented two modifications, numbers 1915 and 2231. Under these modifications the licensee evaluated the maximum differential pressures against which the valves must operate, potential degraded voltage conditions, the thrust required to close, and the recommended and maximum allowable torque switch settings for each valve. The engineering organization supplied the required thrust values and torque switch setting information to the station. Station maintenance personnel subsequently completed in-field performance testing of each MOV using ITI-MOVATS test equipment. The maintenance staff's goal was to establish the torque switch setting such that the thrust at the point of switch trip was 130 % of the required value. In those cases for which the maximum torque switch setting was limiting, the maintenance staff attempted to obtain a minimum of 110 % of the required value. The licensee established these target margins to account for known inaccuracies in the test equipment, as well as other factors such as static rather than dynamic test conditions.

In 1990, the NRC and the industry MOV Users Group (MUG) initiated a program to test various MOV diagnostic test systems to validate the equipment accuracies. The results of that testing indicated that for some systems, the published accuracy values were not met. The NRC issued Information Notice (IN) 91-61, "Preliminary Results of Validation Testing of Motor Operated Valve Diagnostic Equipment," in September 1991 addressing the general concerns raised by the testing. Based on IN 91-61 and information obtained by the licensee through their participation in the MUG, the maintenance organization initiated a program to evaluate the as-left thrust values for all MOVs, and to implement retesting using more accurate diagnostic equipment. The objective of this licensee effort was to directly evaluate the potential for test equipment inaccuracies greater than those published by the equipment manufacturer, and to assess any impact on MOV operability.

The licensee tabulated the required thrust values supplied by engineering, the as-left thrust values measured by the most recent MOVATS test and the calculated margin between the two values. Initially the licensee focused on Unit 3, because it was in a refueling outage and a larger number of valves were available for testing. The valves with less than 20 % margin were tested prior to plant restart. The preventive maintenance program schedule was also altered to test those valves with margins between 20 and 40 % on an expedited basis. The licensee elected to use the Liberty Technology-VOTES system as the standard test equipment. The accuracy of the VOTES system is about 9.2 %. The licensee completed testing of 32 safety-related Unit 3 valves, about one third of the safety-related Unit 3 MOVs. Many of the as-found thrust values obtained using VOTES were significantly less than those measured during the previous MOVATS test. Eight Unit 3 MOVs developed less than the minimum required thrust when tested using VOTES. For each of these valves the licensee initiated a non-conformance report and adjusted the torque switch settings to achieve the required thrust, plus a margin of greater than 10 %. Two of the valves with inadequate as-found thrusts were the inboard and outboard high pressure coolant injection (HPCI) steam line isolation valves. The relevant data for these valves is listed below:

		Thrust (lbs.)		
Valve Number	Required	MOVATS As-Left	VOTES As-Found	VOTES As-Left
MO 3-23-015 (Inboard)	16128	20100	14466	18095
MO 3-23-016 (Outboard)	18558	26000	10293	25649

The ability to accomplish the containment isolation function for this penetration is brought into question. The maintenance staff initiated an EIF to track additional analysis and reportability evaluations for each of the valves found with less than the required thrust, including the two

HPCI valves. The licensee had not completed the analysis and reportability determination by the close of the inspection period.

In response to the experience gained during the Unit 3 testing, the licensee identified all Unit 2 valves previously tested with MOVATS that had less than a 35 % margin. The maintenance staff is altering the preventive maintenance and forced outage schedules to retest these valves at the earliest opportunity. The licensee evaluated the Unit 2 HPCI steam line isolation valves. The inboard valve had last been tested using VOTES, and had about a 28 % margin. While the outboard valve had last been tested using MOVATS, the as-left thrust was about 40 % over the required value. The licensee concluded that no immediate operability concern existed.

The station technicians and maintenance engineers were well informed regarding industry developments in this area, and were knowledgeable oi testing techniques. The inspector considered the licensee's approach to evaluating the emerging information regarding MOV diagnostic test equipment accuracy to be proactive and focused on assuring safety. The prioritized follow-up testing program implemented by the licensee on Unit 3 was well planned and consistent with the potential safety significance.

As previously discussed, the licensee attempted to include a minimum 10 % thrust margin during initial MOV testing. The accuracy of the MOVATS test equipment, as published by the vendor, is between 6 and 16 % depending on the operator size. The inspector questioned whether all MOVs had adequate margin to at least compensate for the published MOVATS accuracy values. In response to the inspector's question, the licensee reviewed each safety-related MOV and identified one concern. High pressure service water (HPSW) valve MO-2486 had only a 2 % margin. The MOVATS accuracy for this size operator is about 6 %. Valve MO-2486 is the HPSW return to the river, and is accessible during all normal and accident conditions. In the event that the licensee experienced difficulty in operating the valve, the differential pressure could be reduced by stopping the HPSW pumps, or the valve could be operated manually. The licensee initiated a work order to retest this valve using VOTES, and an EIF to evaluate why the as-left thrust did not include sufficient margin. This oversight appears to be an isolated incident. The completion of licensee root cause analysis and corrective actions will be assured by the EIF. The inspector had no further questions.

6.0 SURVEILLANCE TESTING OBSERVATIONS (61726, 71707)

The inspector observed conduct of surveillance tests to verify that approved procedures were being used, test instrumentation was calibrated, qualified personnel were performing the tests, and test acceptance criteria were met. The inspector verified that the surveillance tests had been properly scheduled and approved by shift supervision prior to performance, control room operators were knowledgeable about testing in progress, and redundant systems or components were available for service as required. The inspector routinely verified adequate performance of daily surveillance tests including instrument channel checks and jet pump and control rod operability. The inspector did not identify any unacceptable co. litions, except as discussed below.

The inspector reviewed the results of Routine Test (RT) 5.57-2, "Generator Hydrogen (H2) Leakage Rate," performed on December 11, 1991. The inspector noted that the calct 'ation for H2 leakage rate (step 7) had been revised by the system engineer. The formula in the procedure needed to be divided by a constant to accurately reflect H2 leakage. The inspector noted that the change to the procedure was initiated without the use of a Temporary Change. In addition, the inspector noted that the calculated H2 leakage was 2763 cubic feet (cu ft) per 24 hours. In the procedure, a note under step 7 states that the normal H2 leakage for this size generator is 600 cu ft per 24 hours. Although the actual leakage was greater than the recommended value, there was no disposition in the test of why the actual leakage was permissible. The test had been signed off by the performer as satisfactory, but had not yet been reviewed by plant staff supervision.

The inspector discussed the above issues with the Shift Manager and the system engineer. According to the system engineer, 600 cu ft per 24 hours is the vendor recommended value. Leakage in excess of this amount will not adversely affect the generator as long as generator pressure can be maintained above 60 psi and the H2 seal oil flow requirements do not exceed the main seal oil pump capacity. The system engineer stated that the Unit 2 main generator has been experiencing elevated H2 leakage for the past several years. During the last refueling outage the licensee attempted to repair the collector end H2 seal, but was unsuccessful in reducing H2 leakage. Troubleshooting during a recent forced outage indicated that the turbine end H2 seal is passing much more flow than the collector end H2 seal. Although about 2800 cu ft of H2 is used per day on Unit 2, the majority of it is routed outside the plant via the seal oil system.

The licensee has inspected all H2 supply piping for leakage using snoop and an explosive detector. The licensee identified two leaks during this search: a valve packing leak external to the plant, and a small leak at the lower endbell on the northeast side of the generator. The licensee repacked the valve, and attempted, unsuccessfully, to repair the small leak on the generator endbell using an external sealant. H2 usage for each unit's generator is routinely monitored by the plant operators. Any increase in H2 usage which could indicate increased leakage would be identified. In addition, licensee industrial safety personnel monitor areas around the generator and the turbine building weekly for the presence of H2. The licensee has not detected an unsafe quantity of H2 in these areas.

The Shift Manager and the system engineer agreed that a procedure change should have been initiated for the change to the calculation in RT 5.57-2. In addition, the reasons for the greater than recommended leakage being acceptable were annotated on the first page of the completed RT to justify acceptability. The system engineer issued a memorandum on January 2, 1992, describing the reasons for the increased H2 usage. On January 16, the change to and results of the RT performed on December 11, were reviewed and approved by the Plant Operations

Review Committee (PORC). The system engineer was counselled by both his management and the PORC regarding the appropriate method for initiating procedure changes. In addition, PORC approved a complete revision to RT 5.57-2 which permanently corrected the calculation for H2 leakage and improved the format of the test. The inspector found that the licensee had appropriately resolved the inspector's concerns and did not have any additional questions.

7.0 MAINTENANCE ACTIVITY OBSERVATIONS (62703)

The inspector observed portions of ongoing maintenance work to verify proper implementation of maintenance procedures and controls. The inspector verified proper implementation of administrative controls including blocking permits, fire watches, and ignition source and radiological controls. The inspector reviewed maintenance procedures, action requests (AR), work orders (WO), item handling reports, radiation work permits (RWP), material certifications, and receipt inspections. During observation of maintenance work, the inspector verified appropriate QA/QC involvement, plant conditions, TS LCOs, equipment alignment and turnover, post-maintenance testing and reportability review. The inspector did not identify any concerns.

The licensee had shutdown Unit 2 on December 5, 1991, due to excessive leakage past the residual heat removal system injection check valves. During this shutdown, several reactor protection system (RPS) fuse failures occurred. During troubleshooting, the licensee identified binding in several scram contactors (GE model CR105D). The licensee had previously replaced these scram contactors for Unit 3 during the refueling outage in October 1991, and had planned to replace the Unit 2 contactors during the next refueling outage in Fall 1992. GE Services Information Letter (SIL) No. 508, "Scram Contactor Coil Life and Maintenance," dated February 23, 1990, identified the need to periodically replace these scram contactors due to failures associated with aging. The failures do not prevent the contactor from performing its safety function, but such failures may cause an inadvertent scram. On December 11, the licensee proceeded to replace the twelve scram contactors associated with the Unit 2 RPS, believing that the binding in the contactors had caused the blown fuses. However, shortly after completion of the contactor replacement on December 14, the licensee identified another blown fuse. The licensee continued troubleshooting and had testing performed at Valley Forge Labs. Valley Forge Labs identified that the fuses had blown due to thermal stress. Material had built up on the fuse clips which prevented the fuse clips from making adequate contact and caused the fuse to heat-up. The licensee replaced the applicable fuse blocks and performed the necessary post-maintenance testing on December 17. In addition, the licensee is evaluating the potential that this problem could exist in other fuse blocks.

The inspector witnessed ongoing troubleshooting and attended several licensee planning meetings at which RPS status and work being conducted were discussed. In addition, the inspector reviewed work orders (WO) R0050280, C0078203, C0078204, C0077854, and C00077852 involving the scram contactor and fuse block replacement. The inspector found that the troubleshooting and maintenance were conducted in a well controlled manner. Licensee management and staff took a safety conscious approach to determining the cause of the RPS problems. The inspector determined that the licensee's resolution of the RPS fuse issue was acceptable and had no further questions.

8.0 RADIOLOGICAL CONTROLS (71707)

The inspector examined work in progress in both units to verify proper implementation of health physics (HP) procedures and controls. The inspector monitored ALARA implementation, dosimetry and badging, protective clothing use, radiation surveys, radiation protection instrument use, and handling of potentially contaminated equipment and materials. In addition, the inspector verified compliance with RWP requirements. The inspector reviewed RWP line entries and verified that personnel had provided the required information. The inspector observed personnel working in the RWP areas to be meeting the applicable requirements and individuals frisking in accordance with HP procedures. During routine tours of the units, the inspector verified a sampling of high radiation area doors to be locked as required. The inspector did not identify any unacceptable conditions.

9.0 PHYSICAL SECURITY (71707)

The inspector monitored security activities for compliance with the accepted Security Plan and associated implementing procedures. The inspector observed security staffing, operation of the Central and Secondary Access Systems, licensee checks of vehicles, detection and assessment aids, and vital area access to verify proper control. On each shift, the inspector observed protected area access control and badging procedures. In addition the inspector routinely inspected protected and vital area barriers, compensatory measures, and escort procedures. The inspector did not identify any concerns.

On December 18, 1991, at about 7:00 p.m., the licensee discovered an individual inadvertently attempting to gain entry to the protected area of the plant with a loaded 9 millimeter handgun. The security force identified the handgun in the individual's duffle bag during performance of the routine protected area access screening activities. The guard immediately took the appropriate actions and the weapon was confiscated. The licensee called the Pennsylvania State Police and informed them of the incident. Licensee plant management initially made a one hour report to the NRC via the ENS. After consultation with the licensee Branch Head-Nuclear Security, the one hour report was rescinded and changed to a logable event. The inspector reviewed the actions taken by security personnel and management during this event. The inspector concluded that members of the security guard force responded well to the event, demonstrating that they were well trained, alert and responsive. The inspector did not identify any unacceptable conditions.

10.0 PREVIOUS INSPECTION ITEM UPDATE (92702, 92701)

(Closed) Notice of Violation NV4 90-13-002, Failure to Perform Electrical Splices in Accordance With Design Requirements and Current Drawings.

During observation of emergency diesel generator (EDG) maintenance activities in 1990, the inspector identified that maintenance technicians were installing unqualified electrical splices in the air start solenoid cables. The installation violated licensee design specification E1317, "Wire & Cable - Notes & Details Power, Control & Instrumentation." As a result of additional follow-up the inspector raised the following three concerns:

- The maintenance package originally called for the correct splice configuration, but had been inappropriately revised by maintenance planning personnel.
- The craftsman obtained the drawing used for the installation from an uncontrolled source. The drawing they used had previously been deleted from the specification.
- The inspector was also concerned whether additional incorrect splices had been installed.

In response to this finding, the licensee completed several short-term corrective actions including removal of the unqualified splices and replacement with the appropriate type. The licensee inspected other splices installed during the diesel work, and found and replaced one additional example on the 'E3' EDG lube oil circulating pump motor. Licensee management discussed the incident and the identified weaknesses with the maintenance planning personnel and craftsman involved. The licensee also issued a letter to all maintenance foreman emphasizing that the use of controlled drawings and verification of the proper revision prior to use is required.

An investigation was performed to access the usage of E1317 in other applications. The licensee reviewed about 100 work packages involving electrical splices to evaluate the application of E1317, and did not identify any discrepancies. A training session covering the use of E1317 and relevant administrative procedures was conducted for maintenance planners and foreman. This training module was incorporated into the continuing training program. The licensee also revised maintenance procedure M521.202, "Procedures for Insulating and Environmentally Sealing 600 Volt Cable Splices on Nuclear Safety-Related Systems, Class IE and Non-Class IE," to include details concerning splice applications.

During the current inspection period, the inspector reviewed the licensee's training material and attendance records, revised procedure M521.202, and documentation of the rework on the inadequate EDG splices. The inspector also reviewed a number of completed maintenance packages that included installation of electrical splices. The inspector did not identify any concerns. The licensee's corrective actions in response to this violation appear to have been effective.

(Closed) Notice of Violation NV4 90-15-001, Failure to Ensure Proper As-Left Emergency Diesel Generator Brush Force.

During a review of completed maintenance procedure M-052-001, "Diesel Generator Maintenance," the inspector identified that all four of the as-found, and three of the as-left EDG brush forces exceeded the procedure acceptance criteria. The independent verification of the as-left values and the maintenance supervision review of the procedure results were both signed as acceptable. In this case the worker, independent reviewer and supervisor verifications were inadequately performed.

In response to the violation, the licensee assessed the acceptability of the actual as-left brush force values, and concluded that no detrimental effects would result. The licensee reviewed similar maintenance packages completed on the other three EDGs and verified that the as-left force values met the acceptance criteria. The licensee identified procedure clarity as a contributor to the problem, and revised procedure M-052-001 to clarify the acceptance criteria. Inadequate verification and reviews by three individuals allowed the discrepancy to go undetected. To address this weakness the licensee discussed the incident with the individuals involved, and with the maintenance staff at a team quality meeting.

Subsequently, ineffective worker and independent verification was identified as a recurring problem at Peach Bottom. NRC Inspection Report 91-30 included a Notice of Violation (NV4 91-30-001) stemming from multiple examples of the type outlined above. The inspector will assess the long-term effectiveness of the licensee's corrective actions to address this recurring problem in conjunction with NV4 91-30-001 during a future inspection. Based on the above, this item is administratively closed.

(Update) Notices of Violation NV 91-33-001, Violation of Automatic Depressurization System Technical Specifications Due to Component Thermal Degradation; and NV 91-33-002, Failure to Implement Adequate Corrective Actions in Response to Identification of Unit 3 Automatic Depressurization System Component Degradations.

Information updating these apparent violations is included in Section 4.0 of this report. The items will remain open pending issuance of the related enforcement action, formal response by the licensee and evaluation of the effectiveness of the licensee's corrective actions.

11.0 MANAGEMENT MEETINGS (71707,30702)

The resident inspectors provided a verbal summary of preliminary findings to the Peach Bottom Station Plant Manager at the conclusion of the inspection. During the inspection, the resident inspectors verbally notified licensee management concerning preliminary findings. The inspectors did not provide any written inspection material to the licensee during the inspection. This report does not contain proprietary information. The inspectors also attended the exit interview for the following inspection during the report period:

Date	Subject	Report No.	Inspector
1/7/92	Emergency Service Water	91-31	Prividy, Shea, Jones, Mannai, Evans

Attachment I
Unit 3 Startup Procedures Reviewed

GP-2	Normal Startup
RT-5.4	Mechanical Overspeed Trip
RT-5.21	Overspeed Test
RT-5.27	Backup Overspeed Trip
RT-5.31	Cross Around Relief Valves Set Point Check
ST-0-016-440-3	Main Steam Relief Valve Manual Actuation
ST-1.1	HPCI Logic System Functional
ST-10.1-3	HPCI Pump Valve and Flow Test
ST-10.2-2	RCIC Pump Valve and Flow Test
ST-13-2	Unit 3 Excess Flow Check Valve Operability