U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No. 50-277/90-22
50-278/90-22

License Nos. DPR-44
DPR-56

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

Dates: October 30 December 3, 1990

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12/28/90
Date

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, which included 57 hours of sustained control room observations, licensee events, surveillance testing, and maintenance.

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Plant Operations

The inspectors maintained sustained observation of control room and plant activities for 57 hours. Plant evolutions and testing were well planned and properly conducted, and the operating crews used appropriate procedures in all activities observed. Shift turnovers were thorough and communications between operations personnel were excellent. Management was actively involved. However, one instance was noted which reflected a lack of attention to detail. An intermediate range monitor was placed in service before it was functionally tested operable.

The inspector performed a walkdown of the emergency diesel generators (EDG). General housekeeping in the EDG rooms was excellent and the EDGs were properly lined-up for automatic operation. The inspector noted a deficiency tag that was not removed following completion of corrective maintenance. This weakness is the subject of a recent unresolved item.

Maintenance and Surveillance

I&C staff personnel demonstrated inquisitiveness and initiative in two separate instances. They identified a high frequency noise generated by energized residual heat removal pumps that caused undervoltage relays on the 4 kv emergency busses to be out of Technical Specification (TS) calibration. Also, a thorough investigation was initiated when a greater than expected number of Unit 3 Rosemount transmitters were found out of calibration during the midcycle outage. The inspectors identified a violation of Technical Specification requirements for failing to have a Plant Operations Review Committee approved procedure for the control of measuring and test equipment (NV4 90-22-03).

Craft workers failed to replace two gaskets during reassembly of a standby liquid control (SLC) explosive valve. The craft did not strictly adhere to the procedure, which called for replacement of all gaskets. Instead they relied on the materials package provided by the maintenance planners which did not contain all the required gaskets. The inspector also identified that a junction box support for the SLC explosive valves had not been properly reinstalled following previous maintenance. The licensee is investigating the root cause and impact (UNR 90-22-02).

Assurance of Quality

The licensee identified a degraded primary containment isolation valve when its seismically qualified backup nitrogen supply bottle was found to be leaking. The licensee did not immediately repair the leak, which allowed the bottle to depressurize. The inspectors identified a second primary containment isolation valve that was inoperable because its nitrogen bottle pressure was less than acceptable. Surveillance data indicated that the bottle had been leaking in excess of the allowable for an extended period. One violation with two examples is being issued for failure to take prompt corrective action in these cases, as required by 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action" (NV4 90-22-01).

DETAILS

1.0 PLANT OPERATIONS REVIEW (71707, 71710, 71715)

The inspector completed NRC Inspection Procedure 71707, "Operational Safety Verification," by directly observing activities and equipment, touring the facility, interviewing and discussing items with licensee personnel, independently verifying safety system status and limiting conditions for operation, reviewing corrective actions, and examining facility records and logs. The inspectors performed 127 total hours of on site backshift inspection, including 24.5 hours of deep backshift and weekend tours of the facility.

1.1 Operational Overview

Unit 2 began the inspection period at 100% reactor power. On November 10, 1990, a load drop to 55% reactor power commenced to change control rod patterns and clean the tube sheets in the condenser water boxes. The reactor returned to full power on November 14. On November 15, the reactor was shutdown when under voltage relays on the emergency buses were found not to be set in compliance with Technical Specifications (TS) setpoint requirements (See Section 2.3). On November 18 the reactor was placed in the startup mode and returned to 100% power on November 25.

At the start of the inspection period, Unit 3 was in cold shutdown for its mid-cycle outage that began on October 27, 1990. The mode switch was placed in startup on November 22, and the unit reached full power on November 30. Power remained at 100% through the end of the period.

A detailed chronology of plant events occurring during the inspection period is included in Attachment I.

1.2 Unit 3 Drywell Tour

On November 9, 1990, the inspectors toured all elevations of the Unit 2 drywell and the outboard main steam isolation valve room. The inspectors assessed housekeeping, general equipment conditions and radiation protection controls. Work in progress was also observed. Overall, housekeeping in the drywell was good. The inspectors noted very few equipment trouble tags and they appeared to be of minor significance. The pre-entrance briefing by Health Physics was thorough, and radiation protection controls and practices observed in drywell work areas were good.

1.3 Sustained Control Room and Plant Observations

The resident inspectors, assisted by a region-based inspector, maintained sustained observation of control room and plant activities for a period of 57 hours. The coverage began at 1:00 pm on Sunday, November 18, and concluded at 10:00 pm on Tuesday, November 20. During that time the inspectors focused on assessing the clarity and completeness of communications, use of and adherence to procedures, operator attentiveness and care in performance of duties, quality of shift turnover, and supervision and management involvement in monitoring activities. During the inspection period a Unit 2 startup was performed, providing the opportunity to evaluate a variety of operations and testing evolutions.

Plant evolutions and testing were well-planned and properly authorized. The operating shift used appropriate procedures in all activities observed. The shift was cautious in conduct of significant activities. Operating conditions were effectively monitored and corrective actions taken when required. At 8:20 pm on November 20 while starting the turbine generator to synchronize to the electrical grid the steam seal pressure decreased, causing a high off gas flow alarm and a decrease in main condenser vacuum. The shift immediately entered OT 106, "Condenser Low Vacuum-Procedure," for an unexplained or unexpected main condenser vacuum decrease. The shift handled this problem in an effective manner and stabilized the plant.

Shift turnovers were thorough. Discussion between operators and panel walkdowns were conducted in a professional manner. Communications by operators both in the control room and in the plant were excellent. Messages were clear and operators consistently implemented the practice of repeating back information. Control rod withdrawal activities were observed over several shifts. Operators were careful and deliberate in withdrawing rods. Senior licensed operator and reactor engineering oversight during control rod withdrawal was generally strong.

One incident occurred during the startup which reflected a lack of attention to detail. After the reactor reached criticality, the reactor operator (RO) noted that the "E" intermediate range monitor (IRM) was not responding to increasing neutron flux. The "C" IRM, which inputs to the same reactor protection system (RPS) trip system, was responding. The shift manager instructed the RO to take the "C" IRM out of bypass and place the "E" IRM in bypass. The RO continued to pull control rods for about 40 minutes until the shift realized that there were less than three operable IRMs in the "A" RPS trip system as required by TS Table 3.1.1. The "C" IRM was originally bypassed because the functional test SI2N-60C-IRM-A4CW, "IRM Channel "A" Calibration/Functional Test," was not done after its high voltage power supply was replaced during the shutdown. Completed procedure GP-11C, "Reactor Protection System Refuel Mode Operation," contained a variance noting that the "C" IRM was inoperable until the functional test was completed. When GP-2, "Normal Plant Start-up," was implemented, step 3.13.9 and 3.13.10 noted that the "C" IRM was bypassed based on the variance in GP-11C. For immediate corrective action, the Shift Manager directed the RO to place the "A" RPS trip system in a tripped condition, stop all reactivity changes, and functionally test the "C" IRM. The test was satisfactorily completed. The licensee initiated an event investigation and management discussed the incident with the personnel involved. The licensee will issue a Licensee Event Report (LER).

Throughout the sustained observation period, the inspectors observed Peach Bottom management actively involved in startup activities. The inspectors concluded that control and conduct of control room activities were adequate.

1.4 Engineered Safeguards Features (ESF) Walkdown

The inspector performed a detailed walkdown of portions of the emergency diesel generators (EDG) to independently verify their operability. The walkdown included verification or review of: system equipment conditions; operating procedures, check off lists and plant drawings; as-built configuration; valve, breaker, instrument and switch alignment; indications and controls; and surveillance test (ST) procedures associated with the EDGs (see Attachment II).

The inspector noted that general housekeeping in the EDG spaces was excellent with no evidence of loose materials, uncleanliness, or component leakage. The inspector found the systems to be correctly lined-up. However a deficiency tag on the #2 EDG governor control switch indicated that the governor would drift, thereby changing load. The deficiency was noted July 11, 1990, during post-maintenance testing. Maintenance Request Form (MRF) 9004603 was initiated at that time. The system engineer and maintenance resolved the problem on August 7, 1990, but the deficiency tag was not removed. Weakness in the licensee's process for removal of these tags following completion of maintenance is the subject of existing unresolved item 90-80-002. The inspector had no further questions.

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

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

2.1 Unit 3 Engineered Safety Feature (ESF) Actuation

On Saturday, November 3, 1990, with Unit 3 in cold shutdown, the RO inadvertently removed power to the "B" RPS bus. As a result, the "Group II/III Outboard Isolation Relays Not Reset" annunciator alarmed, and the "B" standby gas treatment system fan auto-started.

Prior to the event the 'B' RPS bus was energized by its alternate power supply. The Chief Operator directed the RO to restore the 'B' RPS bus to its normal power supply using procedure SO 60F.7.B-3, "Restoration of Reactor Protection System Alternate Feed Following a Trip." Procedure SO 6OF.7.B-3 assumes that the bus is deenergized. It was not the correct procedure for use during this evolution since the bus remained energized from the alternate feed. The RO should have used procedure SO 60F.6.A-3, "Reactor Protection System Power Supply Operations," which included cautions addressing the fact that whenever RPS is transferred between power supplies at Peach Bottom, an ESF actuation occurs. When the RO opened the RPS alternate feed output breakers in accordance with step 4.3.1 of SO 60F.7.B-3, the ESF actuation occurred. He was not expecting the actuation because the incorrect procedure in use did not contain an appropriate caution.

The "B" RPS bus was returned to its motor-generator set using the proper procedure (SO 6OF.1.A-3). The operating crew thought that the event was not reportable because the ESF actuation would have occurred even if the RO had used the correct procedure. They requested the Regulatory Group to evaluate their position. Since the ESF actuation occurred while using the wrong procedure, the event was reported to the NRC on November 7. A LER will be submitted for this event. The inspector had no further questions.

2.2 Unit 2 Potential Primary Containment Breach

2.2.1 Introduction

The primary containment vent and purge lines are isolated by in-series butterfly valves with inflatable boot seals around the discs. The boot seals are normally inflated by instrument air. Since instrument air would be lost during a design basis accident, backup nitrogen (N2) bottles are installed. Licensee analyses and a justification for continued operation (JCO) dated December 27, 1989, assume a maximum boot seal and tubing leak rate of about 125 standard cubic centimeters per minute (SCCM). At this leak rate a minimum gas bottle pressure of 1300 psig is needed to ensure that the seal remains inflated, and the valve leak tight, for 20 days following an accident.

The licensee implemented ST 7.9.2-2, "Daily Check of Seismic Gas Supply Bottle Pressures," Revision 0, to ensure that pressures exceed 1300 psig. If pressure is found below this value the procedure requires the value to be red circled and the bottle immediately replaced. The procedure also directs the operator to notify the responsible system engineer when bottle replacement is required, although no signature documenting completion is required. The ST includes monitoring of other gas supplies; hydrogen and oxygen (H2/O2) analyzers for example. The procedure clearly states that less than minimum pressure in the H2/O2 gas bottles requires that the analyzers be declared inoperable. No specific operability guidance is included addressing the containment isolation valve gas supplies.

2.2.2 Licensee Identified Primary Containment Isolation Degradation

On November 6, 1990, the licensee determined that Unit 2 primary containment integrity had been degraded when the seismic backup N2 supply to inboard drywell purge supply valve AO-2520 was found at 0 psig and was isolated. In-series outboard torus purge supply valve AO-2521A was already inoperable with the boot seal deflated. Unit 2 was in the run mode at 98% power.

AO-2521A had been removed from service on October 30 for performance of Modification 1316. The boot seal had been deflated as part of the tag-out. Technical Specification (TS)

3.7.D.2 required isolating the affected penetration with an operable deactivated valve secured in the closed position. The licensee maintained AO-2520 and inboard torus purge supply valve AO-2521B closed under shift permit 2-90-0469. Following the event the inspector noted that the AO-2521A boot seal supply did not need to be isolated for performance of most portions of the modification. By isolating the boot seal supply when not required, the valve was unnecessarily made inoperable. The inspector discussed this item with licensee staff who indicated that the blocking points for the remainder of the valves subject to the modification had been changed since the event to maintain the boot seal inflated when possible.

On November 5, at about 8:30 am, a non-licensed operator replacing a N2 cylinder bumped the backup N2 supply tubing to AO-2520 and created a leak. He attempted to repair the leak using tape and immediately reported it to the Shift Supervisor (SSV). The SSV wrote a MRF and prioritized it for work the next day. The SSV assumed that the N2 bottle was holding pressure and noted that AO 2520 was already blocked closed, so he did not request immediate repair. The failure to consider the potential effect of the broken tubing on the boot seal and containment integrity indicates a less than adequate understanding of the system design and function. Lack of explicit operability guidance in ST 7.9.2-2 was a likely contributor.

On November 6, at about 10:00 am, an operator performing ST 7.9.2-2 found the N2 bottle for AO-2520 empty. The bottle was replaced and after valving in the new bottle it began to bleed down rapidly, so the operator isolated it. At 12:00 pm, the control room was notified that the seismic backup N2 supply to AO-2520 was isolated, and maintenance was notified to immediately repair the leak.

At about 3:30 pm, following review by the control room and technical staff, the licensee determined that AO-2520 was inoperable due to the lack of a seismic backup N2 supply. TS 3.7.D.2a was entered to restore the inoperable valve within 4 hours. The valve was repaired and declared operable at 3:45 pm. The licensee notified the NRC of the event via the ENS at 4:00 pm. Since it cannot be determined when the bottle reached its low pressure limit (1300 psig), and since the leakage was excessive, AO-2520 was assumed to have been inoperable since 8:30 am on November 5. The fact that about four hours was required for the control room and technical staff to reach a conclusion regarding operability is an additional indication that the role of the backup gas supply in valve operability had not been clearly defined and communicated.

TS 3.7.D.2 does not adequately address the action to be taken when two inoperable in-series containment isolation valves are identified. The format and content of the specification are confusing, and no discrete action statement is included when two valves are inoperable. In the instance described above the licensee implemented the same response prescribed with only a single inoperable valve. TS 3.7.A.3, Primary Containment, allows 24 hours to reestablish primary containment, and an additional 24 hours to reach cold shutdown if it cannot be reestablished. Since the degraded containment penetration isolation capability essentially results in a loss of containment integrity, the licensee concluded that in this case, TS 3.7.A.3 was the appropriate specification, and therefore no TS violation occurred. It is clear that TS 3.7.D.2 is inadequate and should be revised. TS 3.7.A.3 also appears weak in that continued operation for

48 hours is allowed without containment integrity. The licensee's Operations Superintendent and PORC Chairman is continuing to evaluate these TS and their proper application, and committed to provide direction to the operations staff on the proper application.

2.2.3 Additional Inspector Follow-up

On November 7, following the event discussed above, the inspector toured the Unit 2 reactor building spot-checking bottle pressures. The inspector noted that the N2 bottle for ILRT line isolation valve AO-2519 was indicating about 1200 psig, 100 psig below the minimum allowable limit. The inspector notified the Shift Manager and the bottle was immediately replaced.

The inspector reviewed a sample of surveillance test data recorded for AO-2519 since January 1990. Bottle pressure for AO-2519 was recorded at or below 1300 psig from May 3-4, and again from October 20-22. In one case the unacceptable values were not red circled. In neither case was immediate action taken to replace the bottle as required by the procedure. The inspector also noted that since June 1990, the bottle was being replaced frequently. Since August 29, 1990, the bottle was clearly losing over 100 psig per day. This fact was noted by operations in the daily ST. The leakage rate was greater than 125 SCCM (about double) and even in a fully charged condition the seismic backup N2 supply to AO-2519 was probably not capable of providing a 20 day supply. ST 7.9.2-2 was inadequate because it did not contain acceptance criteria addressing the leakage rate. On May 3-4 and since October 1990, AO-2519 was not provided with a 20 day seismic backup N2 supply. The licensee should have declared the valve inoperable and met the provisions of TS 3.7.D.2.

Criteria XVI of 10 CFR 50 Appendix B requires conditions adverse to quality, such as defective materials and components, to be promptly identified and corrected. Failing to immediately repair the backup N2 supply tubing leak for AO-2520 could have allowed a primary containment leak path to occur during a design basis accident. In addition, failing to repair the backup N2 bottle leak for AO-2519 caused the valve to be inoperable for approximately 2 months without complying with a TS action statement. These are two examples of a violation of Criteria XVI of Appendix B (NC4 90-22-01).

Based on personnel interviews, it appears that notification to the system engineer required by the procedure was not being made. The licensee had implemented a Plant Performance Monitoring Program (PPMP) which included review by the system engineer of surveillance test data for some systems. Data associated with ST 7.9.2-2 was not included in the PPMP.

The inspector also questioned the licensee's process for implementing and tracking JCOs to ensure that supporting assumptions or plant conditions subject to change are appropriately monitored and reverified. In this case, ST 7.9.2-2 was not adequate to ensure continued valve operability, or to periodically verify that the limiting assumptions included in the JCO remained valid. Only one of the two significant variables, pressure, was being monitored. No qualitative or quantitative assessment of leak rate, such as rate of bottle pressure decay, was implemented.

The inspector noted that the seismic, safety-related backup gas supply for the boot seals on the primary containment vent and purge line isolation valves had been modified on Unit 3. The gas bottles were removed and the containment atmospheric dilution (CAD) system hard-piped to the seals. This modification will be implemented on Unit 2 during January 1991. The gas bottles are considered a support system for the isolation valves, and bottle failure requires declaring the associated valve inoperable. The CAD system is designed to assist in primary containment atmosphere control following an accident. TS allow CAD to be inoperable for thirty days with the unit at power. Replacing the N2 bottles with a CAD tie-in effectively expands the function of CAD, making it a containment isolation support system. The inspector questioned the licensee regarding the application of the CAD and containment isolation valve TS in the event of CAD inoperability, and whether a change to the TS should have been processed in support of the modification. The licensee agreed to evaluate this area and discuss the results with the inspector.

2.2.4 Significance Assessment

Even though the seismic backup N2 supply to AO-2520 was lost, and the backup supply for AO-2519 exhibited excessive leakage, an actual breach of primary containment did not occur. Normal instrument air kept the boot seal inflated. During a design basis accident, which includes a loss of offsite power, a primary containment leak path past AO-2520 and AO-2519 or AO-2521A would have existed when the boot seal deflated. The leakage path through AO-2520 existed for a maximum of 31 hours. While the excessive leakage associated with AO-2519 existed for an extended period, the boot seal still would have remained inflated following a design basis accident for a period of time.

Based on historical test data, it appears that leakage past deflated boot seals of these valves would not have been excessive. In February 1980, a local leak rate test was performed on a similar valve (torus vent valve AO-3511). With the boot seal deflated to only 15 psig, the leakage past the valve increased about 6500 cubic centimeters per minute (ccm). Another local leak rate test was performed on a similar valve (torus vent valve AO-2511) in December 1980. With the boot seal deflated to 0 psig, the leakage past the valve increased 4800 ccm. For comparison, the maximum allowable leakage rate at peak accident pressure (La) for Peach Bottom Unit 2 is 125,417 sccm and .60 La is 75,256 sccm. The as-left containment leakage rate prior to Unit 2 startup in 1989 was 58,288 sccm. There appears to be sufficient margin to the maximum leakage rates including leakage past deflated boot seals. Based on the factors described above, the inspector concluded that the safety significance of the events were minimal.

2.2.5 Corrective Actions

The licensee performed an evaluation of the events and reached conclusions similar to the inspector. The inspector discussed the results of this evaluation and the planned actions with licensee staff and management during a meeting on November 30, 1990. The analysis performed by the licensee and presented at that meeting was comprehensive, and the proposed corrective actions appear appropriate. The licensee committed to perform the following:

- o provide immediate verbal operator training and follow-up written instruc'ions to improve the understanding of the backup nitrogen system and its relationship to equipment operability;
- o implement a near-term temporary change and long-term permanent revision to ST 7.9.2-2 to include explicit guidance on operability and to address increased gas leak rates;
- o heighten operator sensitivity to proper review and disposition of surveillance test results;
- o the system engineer will review results of ST 7.9.2-2 daily to aid in early identification of increased leakage;
- o the licensee will complete their evaluation of TS 3.7.D.2 and 3.7.A.3 and will train operators concerning the correct interpretation, and
- o complete planned modifications to remove the gas bottles and install a backup supply from the safety-related CAD system.

Additionally, the licensee indicated that other surveillance tests requiring notification of system engineers would be revised to require operator signature that the notification is complete. The licensee will compile a complete list of JCOs currently in effect and will establish a method for tracking JCOs to ensure that they remain valid and are properly implemented. The inspector had no further questions.

2.3 Unit 2 Shutdown for Out of Calibration Voltage Relays

On November 15, 1990, at 1:30 p.m. Unit 2 commenced a shutdown from 100% after entering TS 3.0.C due to out of calibration 4160 V emergency bus degraded voltage relays. TS 3.0.C requires the reactor to be in hot shutdown in 6 hours and cold shutdown in 36 hours. Degraded voltage relay 127E, less than 98% bus voltage, and 127Y, less than 89% bus voltage, act to: (1) trip the associated bus feeder breaker; (2) initiate automatic transfer to the alternate offsite source; and (3) start the EDGs on failure of automatic transfer to the alternate offsite source.

About 2 years ago a modificati^n replaced the existing ITE solid state relays used for this application with tighter toleranc , SEA Brown Boveri, type 27N high accuracy degraded - voltage relays. Once a cycle th relays are removed, bench calibrated, reinstalled and retested using a variac on the potential transformer (PT) output (120 VAC) to confirm the trip and reset voltage setpoints. During the Unit 3 midcycle outage the relays associated with the emergency buses were calibrated using procedures SI-2K-54-E12, E22, E32, E42-XXCO, "Calibration Check of E12, E22, E32, E42, 4160 V Undervoltage Relays." After bench testing, the relays were reinstalled and retested. I & C technicians had to slightly readjust several relays after they were reinstalled. An I & C engineer reviewing test data questioned these relay readjustments. An oscilloscopic analysis of the PT output revealed a high frequency noise (about 2200 Hz) imposed on the 60 Hz waveform. This added 3 to 4 volts to the peak PT output voltage. The

127E and 127Y relays sense only peak voltage, therefore this noise directly affected the trip point. Other voltage relays are electro-mechanical type and were unaffected.

The TS required tolerance for the relays, plus or minus 0.3% of the setpoint, was not met. Further investigation determined that an energized RHR pump motor was the source of the noise. The noise signal was passed to the 4160 V bus and was being transmitted to the relays through the PT. The licensee found that 3 to 4 volts are added for each energized RHR motor. General Electric confirmed that the design of the RHR pump motor induces this harmonic frequency. Since the TS setpoints could not be assured, the licensee entered TS 3.0.C and shut down Unit 2.

The relays were removed and returned to the manufacturer for installation of a high frequency filter that blocks all frequencies above 180 Hz. In addition, the licensee; (1) initiated a study of the electrical system to determine if 2200 Hz is a resonant frequency, explaining the magnitude of the oscillations; (2) initiated Nonconformance Report (NCR) 90712; and (3) performed a 10 CRF 50.59 review of the relay modification and the effect of the induced voltage oscillation on the power distribution system. Initial review indicated that the phenomenon would not cause any significant effect.

The inspector reviewed NCR-90712, the associated 10 CFR 50.59 review, the surveillance procedures, and discussed the event with plant personnel. In addition, the inspector observed various stages of the frequency testing of RHR motors on Unit 2 and relay removal and replacement. The immediate corrective actions were appropriate and timely. The I & C engineer demonstrated a questioning attitude and knowledge of the equipment in identifying the problem. The follow-up investigation is ongoing to study long-term effects on the power distribution system. The inspector had no further questions at this time.

2.4 Unit 3 Safety Relief Valve Actuation During Testing

On December 2, 1990, during performance of surveillance test ST 1.9, "Automatic Depressurization System (ADS) "B" Logic System Functional," the licensee inadvertently energized a portion of the ADS logic. This caused one of the main steam safety relief valves (SRV) to lift. The actuation was momentary, the valve immediately reseated, and no significant reactor transient was experienced. The licensee later reported the safety system actuation to the NRC via ENS.

Steps 1 through 8 of the procedure involve activities in the C32 panel. Step 9 directs the performer to momentarily jumper two points in the C33 panel. A caution immediately preceding step 9 states, "CAUTION, The next step is performed in panel C33." Step 9 also requires double verification of correct performance of the jumper placement. During performance of the test, the technicians did not relocate from panel C32 to panel C33. They did not adequately perform the double verification, and the jumper was applied in panel C32 not C33, causing the SRV to lift. Post-event interviews conducted by the licensee identified that one of the two individuals involved was performing the steps while the second was reading the steps from the procedure. Double verification was not being performed. The inspector reviewed the procedure and it appeared to provide adequate and clear instructions. The licensee initiated an event investigation and is reviewing the event.

3.0 UNIT 3 TORUS COATING INSPECTION (71707)

The licensee had noted some Unit 3 torus coating degradation and resultant corrosion was noted by the licensee during previous inspections (see NRC Inspection Report 89-23). At that time, PECo described two options available to correct the deterioration. The first was to re-coat the torus during the next refueling outage (August 1991). The second was to perform an underwater inspection of the torus, evaluate the data, and repair the damaged areas. In late 1989, PECo decided to re-coat the torus. Further review determined that the second option might be feasible.

During the mid-cycle outage on Unit 3 during this inspection period, an inspection of the torus was conducted under Modification 5241. Three of sixteen bays in the torus were desludged and qualitatively inspected. Photographs of the 3 bays were taken. Eleven one-square foot areas were quantitatively inspected for pitting depth. Divers also took pit samples to determine if microorganism induced corrosion was present. Prior to the inspection, engineering analysis determined that pits less than 40 mils deep would be acceptable. Pits deeper than 40 mils would require evaluation to determine acceptability.

Divers found the coating to be generally between 4 to 6 mils thick. Most pits ranged in depth from 10-20 mils. Fifteen pits were found deeper than 40 mils, with the worst being 65 mils. NCR P90688 was written to track evaluation of the pits exceeding a depth of 45 mils. The licensee concluded that no repairs were needed. These pits are considered to be acceptable until November 1991, based on a corrosion rate of 7 mils per year.

Additional data review is being performed by the licensee's engineering organization. PECo is pursuing both the re-coat and the repair options concurrently. A decision regarding which option will be implemented will be reached by mid-December.

The condition of the Unit 2 torus coating was also considered. The Unit 2 torus was coated one year after the Unit 3 torus. Therefore, its condition is expected to be similar, or better. During the upcoming Unit 2 refueling outage (January 1991), all 16 bays will be desludged and inspected. A final recommendation for Unit 2 will be determined by mid-March, 1991.

The inspectors performed a tour of the torus on November 1 and observed the control and conduct of the underwater inspection. The modification package and NCR P90688 were also reviewed. Licensee response has been appropriate and the inspector had no further questions.

4.0 SURVEILLANCE TESTING OBSERVATIONS (71707, 61726)

The inspectors observed surveillance tests to verify that testing had been properly scheduled, approved by shift supervision, control room operators were knowledgeable regarding testing in progress, approved procedures were being used, redundant systems or components were available for service as required, test instrumentation was calibrated, work was performed by qualified personnel, and test acceptance criteria were met. Daily surveillances including instrument channel checks, jet pump operability, and control rod operability were verified to be adequately performed. The following tests were observed during the inspection period:

SI3F-7G-118-A1CO	"Calibration Check of Main Steam Line Hi Flow Instrument DPT/DPIS 3-2-116A," observed on October 30;
ST 30.07A-19	"LLRT-Panel 30S199 Expansion Joints," observed on October 31;
SI3L-6-52-A1CO	"Calibration Check of Reactor Level (Narrow Range) Loop LT 3-6-52A & PT 3-6-53B," observed on November 5;
SI3L-13-83-XXCQ	"Calibration Check of RCIC Steam Line High Flow Instrument DPIS 3-13-83," observed on November 6.
ST 8.1	"Diesel Generator Full Load Test," observed on November 1;
SI13L-3-231-A3FM	"Functional Test of Scram Discharge Volume Level Instruments LS-3-3-231A/C/F," (Unit 3) on November 14;
SI13L-2-231-A3FM	"Functional Test of Scram Discharge Volume Level Instruments LS-3-3-231A/C/F," (Unit 2), on November 16,
ST 5.3	"Inoperable Isolation Valve Position Daily Log," on November 8.

5.0 MAINTENANCE ACTIVITY OBSERVATIONS (71707, 62703)

5.1 Routine Observations

The inspectors reviewed administrative controls and associated documentation, and observed portions of ongoing work. Administrative controls checked included blocking permits, fire watches and ignition source controls, QA/QC involvement, radiological controls, plant conditions, TS LCOs, equipment alignment and turnover information, post-maintenance testing and reportability. Documents reviewed included maintenance procedures, maintenance request forms (MRF), item handling reports, radiation work permits (RWP), material certifications, and receipt inspections. The following maintenance activities were observed:

MRF 9005391	Reassemble the 3A Standby Liquid Control System Explosive Valve, observed on October 31;
MRF 9007084	Replace Limit Switches on AO-2521A, observed on November 8,
TCF 90-0358	Troubleshoot Diesel Driven Fire Pump auto start problem observed on November 27,
MRF 9064872	Rebuild instrument nitrogen compressor observed on November 28.

5.2 Reassembly of the Unit 3A Standby Liquid Control Explosive Valve

On October 31, 1990, the inspector observed work performed under MRF 9005391. Maintenance craft disassembled the Unit 3A standby liquid control (SLC) system explosive valve to provide a vent path for leak rate test ST-30.11.02, "LLRT Standby Liquid Control."

Maintenance craft reassembled the explosive valve using maintenance procedure M-011-002, "Standby Liquid Control XV-14, Explosive Valve Maintenance," Revision 1. Most work was performed well and in accordance with the procedure. However, the inspector questioned the craft concerning why only two of four flange gaskets were being replaced. They stated that the MRF and the procedure did not require replacing two of the four gaskets. The inspector pointed out that step 3.2.9 of procedure M-011-002 stated that gaskets are not reusable and should be replaced upon reassembly. Step 5.4.12 of the procedure also stated to install new gaskets. The craft stopped work and consulted the maintenance planners. The gaskets were inadvertently omitted from the job package by the planners. The craft obtained two new gaskets from the store room and installed them. The inspector noted no further problems with the reassembly of the explosive valve.

The inspector questioned the mechanical planner foreman and the planning and scheduling maintenance supervisor concerning the omitted gaskets. He stated that the job planner had used the history file to plan this job. The history file incorrectly called for two gaskets. To prevent recurrence the history file was updated to require using four gaskets. The inspector spoke to the Maintenance Superintendent concerning the maintenance craft failing to follow the procedure. Licensee management discussed the incident with the craft involved. The need for careful adherence to procedures, and not to rely totally on the package as provided by maintenance planning, will be addressed during the next all-hands meeting.

On November 2, the inspector walked-down the SLC system following completion of the maintenance activity. Two electrical junction boxes that supply power to the A and B explosive valves did not appear to be properly supported. The boxes were free to move, potentially straining the explosive valve electric leads. In addition, four spacers between the explosive valve flange and spool piece flange for each valve were missing.

The inspector questioned system and nuclear engineering personnel concerning the missing spacers and questionable junction box support. Engineering determined that the missing spacers have no effect on system operability. An equipment trouble tag was placed on the explosive valves to replace the spacers at the next available opportunity. The junction boxes were secured on November 2. Since the boxes had not been disturbed during performance of the observed MRF, the system engineer performed a MRF history search. It appears that the junction boxes had been disconnected from their pedestal since September 6, 1989. In response to the inspector's concern regarding the impact of the unsecured boxes on system seismic qualification, an action request was submitted to nuclear engineering. This item will remain unresolved pending completion of engineering's review (UNR 90-22-02).

5.3 Unit 3 Rosemount Transmitters Out of Calibration

5.3.1 Overview

During the Unit 3 midcycle outage I&C personnel determined that 23 of 45 Rosemount 1153 transmitters were outside the expected calibration band. Only one transmitter, the automatic depressurization system confirmatory low water level transmitter, was found outside its TS allowable range. The licensee would normally expect to recalibrate about 5 of the 45 transmitters. I & C personnel performed a detailed investigation and determined the contributors to be:

-- 7 transmitters were previously calibrated with measuring and test equipment (M&TE) that was later found to be out of calibration during its periodic M&TE recalibration;

-- 4 transmitters were calibrated during the last outage with M&TE of the wrong range;

-- 4 transmitters were calibrated during the current outage with M&TE later found to out of calibration during its periodic M&TE re calibration;

-- 4 transmitters requiring use of dry test equipment were calibrated with equipment previously used in wet applications, causing inaccuracy; and

-- 1 transmitter was previously calibrated acceptably but exhibited greater than expected drift that will be monitored by the licensee,

-- no reason for the remaining 3 out of calibration transmitters was found, however, historically 3 or 4 transmitters in this size population have been found to drifted this amount during the routine calibration check.

The I&C department determined that the three main contributors to this problem were use of incorrect equipment by technicians, failing to disposition M&TE non-conformance reports when instruments were found to be unacceptable during routine recalibration, and failure to segregate and control issuance of wet and dry M&TE.

5.3.2 Licensee Investigation and Corrective Action

The licensee retrieved M&TE non-conformances for the past year. Of immediate concern was the status of Rosemount transmitters in Unit 2, which was operating. During the Unit 2 midcycle shutdown, only 4 of 40 transmitters were found outside the acceptable band, none were outside the TS required range. I&C personnel reviewed calibration records in light of the non-conformances and all Unit 2 transmitters were satisfactory. All Unit 3 transmitters were reviewed and several transmitters were recalibrated.

In the past, control and issuance of M&TE and disposition of M&TE non-conformances were handled and reviewed by experienced personnel. During a several month period in 1989, the I&C department was realigned within the licensee's organization on two separate occasions. This realignment caused significant changes in reporting relationships, procedures and guidance available and the management and supervisory team involved. In addition, the I&C engineering function was transferred out of the I&C department and several personnel transfers occurred. The end result was that supervisory oversight of some M&TE functions was lost. A clerk was left to track M&TE non-conformances and was not acting on them. The second contributor, segregation of M&TE, was established as a formal policy at Peach Bottom, but was practiced by the technicians. Turnover in the I&C staff appears to have allowed implementation of this practice to become inconsistent.

The disposition of non-conformances for M&TE was reassigned to the Maintenance/I&C electrical supervisor. Independent review of this program was assigned to the Electrical/I&C components engineer. To respond to the segregation issue, additional M&TE is being purchased and a segregation program is being developed. All hands meetings discussing this area were held and formal training in this area is being developed. Finally, the licensee developed a draft Maintenance Guideline MG 11.3-1, "Control and Use of Measuring and Test Equipment."

5.3.3 Inspector Follow-up

The inspector determined that the licensee demonstrated initiative and inquisitiveness in identifying the weakness. The investigation and follow-up were detailed and thorough. Determination of root causes was generally accurate and immediate corrective actions were adequate. Licensee management ensured proper assessment of the potential impact on the operating unit.

The inspector identified that the licensee had not established PORC and QA approved procedures establishing and implementing a M&TE program. While several guidance documents on control of M&TE existed, they were neither PORC nor QA approved. The licensee's proposed corrective actions included development of an additional guideline. TS 6.8.1 states in part that written procedures and administrative policies shall be established, implemented, and maintained that meet the requirements of 5.3 of ANSI N18.7-1972 and Appendix A of Regulatory Guide (RG) 1.33 (November 1972). Section 5.3.6 of the ANSI standard and Section H of the RG require procedures for the control, storage and use of M&TE. TS 6.5.16 states in part that PORC shall be responsible for review of all procedures required by TS 6.8. The inspector informed the licensee that the above constitutes a violation of TS (NC4 277/90-22-03).

10 CFR 50 Appendix B, Criterion XII, requires control of M&TE. The inspector spoke with Quality Assurance personnel to determine their involvement with audits conducted in this area. Between October 10 through 25, 1989, QA audit PA89-24 was conducted to verify the adequacy of M&TE control by Maintenance, I&C, and Technical personnel. Two Corrective Action Requests (CARs) were initiated. The CARs identified several performance deficiencies. Neither CAR identified that there was not a PORC and QA approved procedure for controlling M&TE. However, the audit did mention that there was an Administrative Procedure being drafted at the time. A CAR was not issued to track the progress of the procedure and the procedure was not issued. Prior to the close of the inspection period the licensee's plant management and QA indicated that it appeared that a procedure was needed and would be developed.

The inspector concluded that transition of the I&C organization and associated personnel transfers were not adequately planned to include steps to identify responsibilities and to ensure that adequate staff resources and knowledge were maintained to implement them. A second factor was the lack of a clearly established program procedure at the station that would have helped to preclude the problems noted.

6.0 RADIOLOGICAL CONTROLS (71707)

During the report period, the inspector examined work in progress in both units and included health physics procedures and controls, ALARA implementation, dosimetry and badging, protective clothing use, adherence to RWP requirements, radiation surveys, radiation protection instrument use, and handling of potentially contaminated equipment and materials.

The inspector observed individuals frisking in accordance with HP procedures. A sampling of high radiation area doors was verified to be locked as required. Compliance with RWP requirements was verified during each tour. RWP line entries were reviewed to verify that personnel had provided the required information and people working in RWP areas were observed to be meeting the applicable requirements. No unacceptable conditions were identified.

7.0 PHYSICAL SECURITY (71707)

The inspector monitored security activities for compliance with the accepted Security Plan and associated implementing procedures, including: security staffing, operations of the CAS and SAS, checks of vehicles to verify proper control, observation of protected area access control and badging procedures on each shift, inspection of protected and vital area barriers, checks on control of vital area access, escort procedures, checks of detection and assessment aids, and compensatory measures. No inadequacies were identified.

8.0 PREVIOUS INSPECTION ITEM UPDATE (71707, 92700)

(Closed) Unresolved Item 88-13-001, Applicability of Shutdown Cooling Technical Specifications.

The Peach Bottom TS do not require instrumentation and logic associated with the shutdown cooling (SDC) isolation on low reactor water level and high reactor pressure to be operable during cold shutdown. The inspector expressed concern that the TS did not require operability during the mode in which it is used. Also the inspector questioned whether adequate surveillance testing was performed during periods of cold shutdown to ensure that the SDC isolation instrumentation and logic would function.

In response to the inspector's concern the licensee reviewed the scope and performance schedule for SDC isolation instrumentation and logic testing. The scope or frequency of the following surveillance test procedures were revised to ensure that this isolation function remains operable during periods of cold shutdown:

SI(2)3P-2-128-(A-B)1FM, "Functional Test of Reactor Vessel Pressure Instrument PS2-2-128(A-B),"

SI(2)3P-2-128-(A-B)1CQ, "Calibration Check of Reactor Vessel Pressure Instrument PS2-2-128(A-B),"

SI(2)3A-2-RPS-(A-D)1FM, "Functional Test of RPS Card File," and

ST 1.3.4, "PCIS Logic System Functional Test for Shutdown Conditions."

The inspector reviewed the content of these procedures, and verified that they are scheduled by the licensee's surveillance test scheduling program at the appropriate frequencies.

Operability of the SDC isolation feature during cold shutdown is not included in the BWR 4 Standard Technical Specifications. The licensee is in the process of upgrading to the Improved Standard Technical Specifications. The need to include additional SDC TS will be evaluated during that upgrade effort. In the interim, established surveillance testing is adequate to ensure SDC operability.

9.0 MANAGEMENT MEETINGS (30703)

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. No written inspection material was provided to the licensee during the inspection. This report does not contain proprietary information. The inspectors also attended the exit interviews for the following inspections during the report period:

Dates	Subject	Report No.	Inspector
10/19/90	Environmental Qualification Program and Open Item Review	90-20	R. Paolino
11/2/90	Routine Radiological Controls/ Controls Review	90-21	D. Chawaga J. Noggle

ATTACHMENT I

Facility and Unit Status

Unit 2

October 29	Reactor power at 100%.
November 10	Power reduced to 55% for control and pattern adjustment and cleaning of condenser water boxes.
November 14	Power increased to 100%.
November 15	Reactor shutdown due to replacement of undervoltage relays on emergency buses.
November 18	Reactor startup.
November 20	Turbine synchronized to grid.
November 25	Power increased to 100%.

Unit 3

October 29	Reactor in cold shutdown for mid-cycle outage.
November 22	Mode switch to startup.
November 28	Reactor power reached 94% but was reduced to 65% when the 'C' reactor feedpump coupling broke and to perform a control rod pattern adjustment.
November 29	Reactor power decreased to 75% to return the 'C' reactor feedpump to service.
December 1	Reactor power reaches 100% and remained there through the end of the period.

ATTACHMENT II

FSF SYSTEM WALKDOWN: EMERGENCY DIESEL GENERATORS

Operating and Checkoff Lists Reviewed and Walked-down:

SO52.A.1.A	"Diesel Generator Manual Startup from the Control Room," Revision 2, 2/8/90.
COL 52A.1.A-2	"E2 Diesel Generator Manual Standby," Revision 2, 7/15/89.
SO52A.1.B	"Diesel Generator Manual Startup from the Local Control Panel," Revision 1, 7/13/89.
SO52A.1.C	"Diesel Generator Manual Startup from the Local Diesel Gauge Panel," Revision 1, 7/20/89.
SO52A.1.D	"Diesel Generator Lineup for Automatic Start," Revision 0, 2/6/89.
SO52A.7.A	"Diesel Generator Manual Emergency Startup," Revision 2, 7/13/89.
SO52A.8.A	"Diesel Generator Daily Shutdown/Pre-Startup Inspection," Revision 4, 8/20/90.
SO52A.8.G	"Diesel Generator Running Inspection," Revision 4, 8/20/90
SO52B.1.A	"Diesel Generator Synchronization and Loading," Revision 4, 7/27/90
SO52B.1.B	"Diesel Generator Automatic Start," Revision 1, 3/20/89
SO5LB.2.A	"Diesel Generator Shutdown; Diesel Carrying One 4KV Emergency Bus," Revision 4, 9/14/90
SO52B.2.C	"Diesel Generator Shutdown; Diesel Generator Breakers Open," Revision 1, 9/14/90.
SO52C.1.A	"Diesel Generator Starting Air System Startup," Revision 0, 2/6/89.
COL 52C.1.A-2	"E2 Diesel Generator Starting Air System Startup," Revision 4, 7/25/90.
SO52E.3.A	"Diesel Generator Jacket Coolant/Air Coolant Fill," Revision 0, 2/6/89.
COL 52E.3.A-2	"E2 Diesel Generator Jacket Coolant/Air Coolant System Fill," Revision 1, 5/17/89
SO52G.3.A	"Diesel Lube Oil System Fill," Revision 0, 2/6/89.

COL 52G.3.A-2	"E2 Diesel Lube Oil System Fill," Revision 1, 5/5/89
SO52D.1.A	"Diesel Fuel Oil System Normal Operations," Revision 2, 8/20/90.
COL 52D.1.A-2	"E2 Diesel Fuel Oil System Operation," Revision 1, 5/17/89.
SO52D.3.A	"Diesel Fuel Oil Storage Tank Filling," Revision 1, 2/1/90.
COL 52D.3.A	"Diesel Fuel Oil Tank Filling," Revision 1, 4/15/89.
COL 52D.3.B-2	"E2 Diesel Fuel Oil System Fill," Revision 1, 3/16/89.
Exhibit A-8:C	"Locked Valve List-Common," Revision 11, 9/11/90.

Documents Reviewed:

Temporary Plant Modification Log

P&ID M377, Sheets 1, 2, 3 & 4, "Diesel Generator Auxiliary Systems."

P&ID M335, "Diesel Generator, Boiler Building Shop and Warehouse Temperature Control Diagram."

P&ID M323, "Fuel and Diesel Oil System."

Peach Bottom Atomic Power Station, Units 2 and 3, Updated Final Safety Analysis Report.