U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No. 50-277/89-22 License No. DPR-44
50-278/89-22 DPR-56

Licensee: Philadelphia Electric Company
Correspondence Control Desk
P. O. Box 7520
Philadelphia, Pennsylvania 19101

Facility Name: Peach Bottom Atomic Power Station Units 2 and 3

Inspection At: Delta, Pennsylvania

Dates: September 3 - October 7, 1989

Inspectors: T. P. Johnson, Senior Resident Inspector
R. J. Urban, Resident Inspector
L. E. Myers, Resident Inspector

Approved By: L. T. Doerflein 11/14/89
L. T. Doerflein, Chief, date
Reactor Projects Section 2B,
Division of Reactor Projects

Summary

Areas Inspected: Routine, on site regular, backshift and deep backshift resident inspection (193 hours Unit 2; 135 hours Unit 3) of accessible portions of Unit 2 and 3, operational safety, radiation protection, physical security, control room activities, licensee events, surveillance testing, Unit 3 refueling and outage activities, maintenance, and outstanding items.

Results: Three licensee identified Technical Specification violations were reported in LERs: (1) failure to establish a firewatch for three hours (section 6.2.1); (2) failure to trip rod block logic for about three hours (section 6.2.2); and (3) failure to estimate ventilation flow for five hours (section 6.2.3). Reportable and non-reportable events were reviewed (section 4.2). Three of these involved delays between the identification of the abnormal conditions on Unit 3 and licensee determination of reportability and review of effect on Unit 2 (sections 4.2.1, 4.2.3, 4.2.8 and 11.1). Two system isolation events occurred during troubleshooting activities (section 4.2.4 and 4.2.7). Also, Unit 2 tripped from 100% power when a main steam isolation valve unexpectedly closed during surveillance testing (section 4.2.11). Effective coordination between operations and engineering was noted during the Unit 3 emergency cooling tower (ECT) test (section 5.2), and between the control room and the refueling floor during Unit 3 core reload (section 5.1).

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DETAILS

1.0 Persons Contacted

G. A. Bird, Nuclear Security Specialist
J. B. Cotton, Superintendent, Operations
T. E. Cribbe, Regulatory Engineer
G. F. Daebeler, Superintendent, Technical
* J. F. Franz, Plant Manager
D. P. LeQuia, Superintendent Services
D. R. Meyers, Support Manager
F. W. Polaski, Assistant Superintendent, Operations
K. P. Powers, Peach Bottom Project Manager
J. M. Pratt, Manager, Peach Bottom QA
G. R. Rainey, Superintendent, Maintenance
*D. M. Smith, Vice President, Peach Bottom Atomic Power Station

Other licensee and contractor employees were also contacted.

*Present at exit interview on site and for summation of preliminary findings.

2.0 Facility and Unit Status

2.1 Unit 2

At the beginning of the period, the unit was at 100% power. On September 16, 1989, reactor power was reduced to 80% when copper concentration in the reactor feedwater exceeded the administrative limit. On September 20, 1989, the licensee began to raise power when copper concentration decreased below the administrative limit. On September 21, 1989, the reactor power increase was halted at 90% to troubleshoot control problems with the "C" reactor feed pump. On September 22, 1989, reactor power was increased to 96% to continue troubleshooting the "C" reactor feed pump. Reactor power was increased to 100% on September 25, 1989, and remained there until a reactor scram occurred on October 5, 1989. The unit was shutdown through the remainder of the period.

2.2 Unit 3

Unit 3 continued in its seventh refueling outage. Fuel reload into the core began on September 10, 1989, and was completed on September 20, 1989. Reactor vessel reassembly began on September 24, 1989, and was completed on October 4, 1989. At the end of the inspection period system restoration, testing and maintenance was in progress to support the next major milestone, the reactor pressure vessel hydrostatic test.

2.3 Common

The Peach Bottom SALP management meeting was held on site on September 18, 1989. On October 5, 1989, the NRC terminated the requirements of the Peach Bottom Shutdown Order that was issued March 31, 1987.

3.0 Previous Inspection Item Update (92701, 92702)

3.1 (Closed) Unresolved Item (278/86-20-01). Uncoupling of Unit 3 control rod 10-47 during Cycle 7. On November 5, 1986, during a reactor startup, control rod 10-47 had indications of being uncoupled when given an overtravel verification. The control rod was then inserted, the reactor was shut down, and the mode switch was placed in refuel.

Troubleshooting determined that the control rod would remain coupled when withdrawn with drive pressures below 350 psid. When drive pressures were increased, and the control rod was continuously withdrawn, the control rod would uncouple. The licensee concluded it was a control rod drive problem (CRD), not a hydraulic control unit (HCU) problem.

The control rod and drive were operated throughout cycle 7. Operation of the control rod was per a safety evaluation. Only notch withdrawal of the rod using drive pressures below 300 psid was allowed. The control rod operated the rest of the cycle without any operational problems.

Before the CRD was exchanged during the current outage, the control rod was lifted and inspected. The bottom of the control rod showed no abnormalities but the locking plug had a nick. The spud area of the drive was also inspected and the uncoupling rod was observed to be bent.

When the CRD was removed for maintenance, the bent uncoupling rod was confirmed. The bend occurred in an area as to make the uncoupling rod sit higher in the spud than normal. When the filter was removed, excessive crud was noted inside and the dose rate of the filter was greater than 100 R/hr. This was one of the radiologically hottest drives removed, yet it only operated two cycles. The rest of the drive appeared to be normal.

The licensee believes that the uncoupling problem was caused by three factors. First, the uncoupling rod was bent in a way to make the uncoupling rod closer to the locking plug. Second, the high amount of crud in the filter may have lifted the uncoupling rod to a position in which it could uncouple the control rod. Third, as the seals deteriorated it took higher and higher drive pressures to move the control rod.

At high drive pressures the control rod could build up enough force to hit the bent uncoupling rod and uncouple the control rod from the CRD. The crud in the filter could explain why the problem took two cycles to develop. The new CRD was installed and stroked during the first week of August 1989, and no operational problems were observed.

The inspector had no further questions on this issue.

3.2 (Closed) Unresolved Item (277/88-28-03, 278/88-28-03). Upgrade non-licensed operator exams. The inspector verified that the licensee took action to upgrade the two exams of concern: plant operator and auxiliary plant operator. In addition, the licensee developed a corporate procedure, NGAP Number NA-08Q002, "Qualifying and Progression Examination Process." This procedure became effective July 25, 1989, and ensures that non-licensed operator qualification process, including exams, is kept up to date.

The inspector reviewed the procedure and the formalized process. The inspector had no further questions on this issue.

4.0 Plant Operations Review

4.1 Operational Safety Verification and Station Tours (71707)

The inspector completed the requirements of NRC inspection Procedure 71707, "Operational Safety Verification," by direct observation of activities and equipment, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety system status and limiting conditions for operation, corrective actions, and review of facility records and logs.

The inspectors performed 78 total hours of on site backshift time.

No unacceptable conditions were noted.

4.2 Follow-up On Events Occurring During the Inspection (93702)

4.2.1 Unit 3 Containment Control Piping Outside Design Basis

As part of the safety grade air supply tubing modification (MOD 1316) on Unit 3, the licensee needed maximum displacement values for associated air operated valves during a design basis earthquake. This information was needed to determine if the air tubing would be overstressed. When the level of detail was not available in original design packages, the licensee obtained the services of an engineering firm. In a June 16, 1989, letter to PECo, the engineering firm indicated that excessive valve displacements were calculated for two valves (AO-3509, AO-3510). These valves are part of the containment atmosphere control (CAC) and containment atmosphere dilution (CAD) systems. They are also primary containment isolation valves, and are on one of the nine containment vent paths.

Design drawings indicated that there should be a support located at each valve operator. However, the as-found configuration did not have supports attached to either of the two valve operators. Therefore, during a seismic event excessive displacement would occur. The engineering firm recommended a repair to add a support to both the AO-3509 and AO-3510 valve operators.

In an August 1, 1989, letter to PECo, the firm also stated that stresses in the two inch piping attached to the valves could exceed code allowable. This evaluation was preliminary because it was based on design drawings submitted by PECo that were not field verified. The firm committed to perform a system operability determination based on field verified drawings.

In an August 8, 1989, letter to PECo, the firm stated that the system was inoperable because the piping stresses adjacent to valves AO-3509 and AO-3510 exceed code/licensing commitment limits. In addition to the two supports needed at the valve operators, six additional supports would need rework or repair in order for the system to meet operability requirements. The firm provided these proposed repairs to PECo in a letter dated August 11, 1989.

On September 6, 1989, the licensee made an emergency notification system (ENS) phone call to the NRC concerning a potential failure of both primary containment isolation valves during a seismic event. The licensee also walked down the same piping system on Unit 2 and noted the as-found configuration agreed with the design drawings.

During his review, the inspector discussed this matter with licensee engineers and licensing personnel. The inspector also reviewed the reportability evaluation form, P&IDs, design drawings, nonconformance report P89683-213, correspondence, and observed the as-found system configuration. The inspector questioned the lengthy delay from the date that nuclear engineering was aware that the system was inoperable (August 8, 1989) until it was reported to the NRC on September 6, 1989. See Section 11.0 for further discussion of this issue.

The licensee is currently repairing/reworking the system and the inspector had no further concerns at this time. The inspector will review the licensee's root cause analysis and adequacy of corrective actions when the Licensee Event Report (LER) is issued.

4.2.2 Sewage Release to River

On September 14, 1989, during excavation of a Unit 3 high pressure water line, a section of buried cast iron sewerage line was discovered to have cracked. Untreated water flowed into the administration building pipe tunnel sump. The sump is pumped to the yard drain system which drains to the discharge pond. The duration of the flow from the break was approximately two hours before it was isolated. About 1000 gallons of untreated sewage was released to the discharge pond. The licensee made an ENS call and submitted a special report (see section 12.0).

The inspector reviewed the event and the report, and had no further questions or concerns.

4.2.3 Motor Terminations Not Environmentally Qualified

In late August 1989, the licensee discovered that the Unit 3 "C" residual heat removal (RHR) pump motor termination splices were not in accordance with approved drawings. Therefore, the environmental qualification (EQ) of the terminations were not reviewed for acceptability. The 4160V motor splices were covered by polyvinyl chloride (PVC) sleeves held closed by nylon tie wraps. An approved drawing (ERR P-7194) depicted the terminations to be surrounded by insulating putty and double wrapped with tape.

Since Unit 3 was in a refueling outage, the other three RHR pumps were inspected. All three had similar type suspect motor termination splices. Since all four RHR motors did not meet drawing specifications, they were reworked on September 8, 1989. The licensee also examined all four core spray (CS) pump motor terminations and found them to contain suspect splices. They were also reworked.

On September 14, 1989, nuclear engineering determined that the PVC sleeve met EQ requirements, but the nylon tie wraps holding the sleeve closed did not. Since the environment in the CS rooms would be less harsh than in the RHR rooms after a severe accident, the as-found sleeves met EQ acceptability for the CS motor terminations, but not for the RHR pump motor terminations. On September 14, 1989, the licensee made a four hour ENS phone call at 6:45 p.m. concerning unacceptable EQ splices on all four Unit 3 RHR pump motors.

When the EQ acceptability determination was made, the licensee held a meeting to establish an inspection plan to examine the Unit 2 RHR motor terminations. Unit 2 was at 100% power. The licensee decided to look at the RHR pump motors in the following order: B; D; A; and C. Actions were planned depending on which pumps were found to have non-EQ splices. On September 15, 1989, the licensee determined that the Unit 2 "B" and "D" RHR motors had acceptable splices. Therefore, the "B" loop of RHR was operable. However, at 11:28 a.m., the licensee found the "A" RHR motor to have non-EQ splices. At this time the licensee declared the Unit 2 "A" loop of RHR inoperable (since they also conservatively declared the "C" RHR motor to be non-EQ prior to inspection), and entered Technical Specification (TS) limiting condition for operation (LCO) 3.5.A.5. The LCO required testing other emergency core cooling system (ECCS) components, and a reactor shutdown if the "A" loop was not declared operable within seven days.

The Unit 2 "A" RHR motor termination splices were reworked and satisfactorily tested on September 16, 1989. The remaining "C" RHR pump motor was inspected the same day and was found to have acceptable splices. The "A" loop of RHR was tested and declared operable on September 16, 1989, and the TS LCO was exited.

The Unit 2 "D" CS pump motor splices were inspected on September 14, 1989, and were found acceptable. The three remaining CS pump motors will be inspected during their planned 13 week maintenance windows.

During his review the inspector attended Unit 2 RHR pump motor the inspection plan meeting, reviewed reportability evaluation forms and drawings, and discussed this issue with licensee personnel. The inspector questioned the licensee as to why splices for four RHR and four CS motors on Unit 3 and one RHR motor (A) on Unit 2 were not in agreement with approved drawings. The licensee's investigation of this issue is continuing. The inspector also questioned the lengthy delay between discovery of the questionable splice on the Unit 3 "C" RHR motor (August 24, 1989) and the reportability determination by engineering (September 14, 1989). See Section 11.0 for further discussion of this issue.

The inspector had no further questions or concerns regarding the repairs. The inspector will review licensee's root cause analysis and adequacy of corrective actions when the LER is issued.

4.2.4 Control Room Ventilation Isolation

During troubleshooting activities a control room ventilation isolation occurred. An I&C technician was troubleshooting, in accordance with an approved procedure, a low flow condition in the sample pump for the control room radiation monitoring system. The technician jumpered out two terminal points in order to simulate a low flow condition and the radiation indicating switch actuated unexpectedly. This gave a false high radiation signal to the trip logic of the control room ventilation system causing the isolation. The technician indicated he had followed the procedure exactly. Thus far the licensee has not found the correlation between the contacts jumpered and receipt of the isolation. The procedure appears to be adequate. The licensee is continuing to investigate this issue.

The inspector reviewed logs and the event report, and discussed the item with licensee personnel. The inspector had no further questions regarding the licensee's actions at this time. The licensee intends to submit an LER for this event and the inspector will review the results of the licensee's investigation and adequacy of corrective actions when the LER is issued.

4.2.5 Injured Man Transported Off Site

At 8:20 a.m. on September 20, 1989, a contract employee in the Unit 3 drywell tripped on a piece of equipment on a walkway and injured his left knee. First aid was applied in the drywell which included a splint to the injured leg. The worker was surveyed and was not contaminated. The area under the splint could not be surveyed. The worker was transported off site to Harford Memorial Hospital by ambulance. A survey at the hospital indicated no contamination under the splint or on the worker. The worker apparently suffered a twisted knee injury. The licensee made an ENS call based on off-site notifications to the county.

The inspector discussed this event with licensee personnel. The inspector had no further questions or concerns.

4.2.6 Hurricane Hugo Preparations

The inspector reviewed the licensee's preparations for hurricane Hugo. Technical Specification 3.12, Special Event (SE) procedures SE-3 and 4, and Emergency Response Plan Procedure (ERP) 101 were reviewed. The licensee's actions included ensuring the station was prepared for expected high winds and excessive rainfall as follows:

- -- inspecting the yard and substations for loose objects,
- -- providing for sand bags to prevent flooding of unprotected areas,
- -- checking in plant areas for possible rain runoff, and
- -- verifying availability of off site and emergency power.

The inspector discussed this item with licensee management, reviewed TS and procedures, and verified licensee actions. No unacceptable conditions were noted.

4.2.7 Unit 3 Reactor Water Cleanup (RWCU) Isolation

At 9:02 a.m., on September 26, 1989, an inboard, one-half group IIA primary containment isolation system (PCIS) actuation occurred. The RWCU inboard isolation valve (MO-12-15) received a close signal when differential pressure indicating switch (DPIS) 3-12-124A inadvertently sensed a high flow condition. The inadvertent high flow condition (300%) was caused by a maintenance planner draining the DPIS. In addition, the operating RWCU pump (3B) tripped.

The control room operator responded to the isolation and various alarms. The RWCU system was restored within thirty minutes. A shift technical advisor was sent to the DPIS location to investigate the cause. The STA spotted several maintenance personnel in the area and determined that a maintenance planner had opened two drain valves to the DPIS. The maintenance planner had maintenance request form (MRF) 8907607 in his possession. However, his sole purpose was to gather information to complete sections two and three (investigation and planned action) of the MRF. He did not have paperwork, procedures or permission to troubleshoot the problem (possible clogged instrument lines).

The inspector reviewed the event by performing the following: observing operator response in the control room after the isolation was received; reviewing the reportability evaluation form, electrical prints, the MRF and administrative procedures; and attending the licensee's critique held on September 29, 1989. The critique was thorough. The inspector determined the licensee's immediate corrective actions were adequate. These included: counselling the individuals involved; issuing a memo regarding the status of Unit 3 and the need to follow administrative controls; and disseminating a policy regarding disciplinary action for future similar problems. Corrective actions to prevent recurrence will be reviewed in a future report when the LER is received. The inspector had no further questions at this time.

4.2.8 Unit 3 Emergency Core Cooling System Logic Outside of Appendix R Data Base

On September 27, 1989, nuclear engineering determined that the Appendix R data base was incorrect concerning the Unit 3 "A" residual heat removal (RHR) system and "A" core spray (CS) system logics. When upgraded Appendix R calculations were performed in 1987, three prints used (E-27, sheet 1; M-1-S-40, sheet 25; and M-1-S-65, sheet 70) did not reflect the actual wiring configuration in the plant. However, two other internal wiring prints (E-495, sheet 1; M-1-EE-254, sheet 6) concerning the same systems were correct.

Both the "A" RHR and "A" CS logics are powered from the Unit 3 Division I battery system. The "A" RHR 125 VDC logic is powered from the 3A battery while the "A" CS 125 VDC logic is powered from the 3C battery. Prints E-27, M-1-S-40 and M-1-S-65 show the reverse. Each of the two battery chargers associated with the "A" and "C" batteries receive power from two separate emergency buses (RHR/E33; CS/E13). In turn, a motor control center is located in between the emergency bus and the battery charger (RHR/E334-R-B; CS/E134-T-B). Since the emergency buses and motor control centers are in different areas of the plant than those assumed in the Appendix R calculations, the licensee concluded that an Appendix R separation concern may exist.

On May 24, 1989, the incorrect drawings were discovered and noted in nonconformance report P89411-311. Corrective action at that time was to revise the three non-conforming drawings to make them consistent with the plant configuration. When nuclear engineering reviewed the NCR and its corrective action on May 30, 1989, both the reviewer and the independent reviewer agreed with the disposition. It wasn't until mid-July that another engineer, who was familiar with Appendix R, noted the Appendix R concerns when the drawings were being revised.

Based on these concerns, engineering revised the disposition to swap the power leads between the Unit 3 "A" RHR and "A" CS logics. The package was sent to the site in early September. A maintenance request form (MRF) was written to reverse the wiring. It wasn't until a shift technical advisor reviewed the work package that the question of reportability was raised. Based on information at that time, the licensee made a conservative four hour ENS phone call on September 27, 1989.

During his review, the inspector reviewed electrical schematic drawings, NCR P89411-311, and the reportability evaluation form. The inspector also held discussions with licensee operators and engineers. The inspector questioned whether compliance with Appendix R was actually affected by the drawing error and why the three drawings were incorrect. The inspector questioned how the licensee could ensure themselves that the condition was an isolated case. The licensee could not currently answer the questions and is continuing their investigation; however, the licensee has determined that a request for a drawing change was made in November 1986, and that change was the cause for the three incorrect drawings. The inspector also questioned the long delay between discovery of the Appendix R concern (mid-July 1989) and when an ENS phone call was made to the NRC (September 27, 1989). See section 11.0 for further discussion. As noted above the licensee is continuing to review this issue. The inspector had no further concerns at this time regarding the licensee's proposed actions. The inspector will continue to monitor this issue and review the adequacy of the licensee's corrective actions when the LER is issued.

4.2.9 <u>Unit 2 High Pressure Coolant Injection System (HPCI) Inoperability</u>

On October 4, 1989, at 2:35 p.m., I&C technicians while troubleshooting a thermocouple due to erroneous readings on the HPCI recovery found a broken wire to the HPCI turbine trip solenoid. The broken wire was found in a junction box that had been opened during the thermocouple troubleshooting. The licensee suspects that the wire had become looped over the latch to the junction box and was broken when the door was opened. The system had previously been tested for operability on September 28, 1989, and performed satisfactorily. The HPCI system was declared inoperable upon the discovery. The licensee made a four hour ENS phone call at 6:20 p.m. The broken wire was repaired, and HPCI was tested successfully and declared operable four hours and 20 minutes after the discovery of the broken wire.

The inspector reviewed the event and discussed it with licensee personnel. The inspector had no additional concerns nor questions at this time, and will review the LER when it is issued.

4.2.10 Unit 2 Reactor Feedwater Pump (RFP) Oscillations

On September 20, 1989, while increasing reactor power by 30 MWE, the "C" reactor feedwater pump (RFP) control valve position indication oscillated about 10% from the 20% valve position while responding to the power level change. The operator placed the "C" RFP motor gear unit in manual which stabilized the observed oscillations. The other two operating RFPs responded to the reactor power and water level changes normally.

Operations, System Engineers and General Electric technical representatives met to discuss these initial valve problems. They devised a method to diagnose the problem and formulate operator response to the oscillations by the "C" RFP. The "C" RFP was observed in manual and automatic control during stable power and reactor power level increases. The control valve responded normally. The licensee suspects the control valve linkage to be the problem. Similar oscillations of a lower magnitude were noted during Unit 2 power ascension on this RFP. The licensee decided to bias the "C" RFP control slightly higher than the other two RFPs. The "C" RFP currently is operating stable.

Operators are continuously monitoring the operation of the "C" RFP and they have been briefed on contingency actions if further oscillations are observed.

The inspector attended the related RFP meetings, discussed this item with licensee engineers and operators, verified operator knowledge and awareness of the condition and associated contingency actions, and observed RFP operations. The inspector had no additional concerns or questions at this time.

4.2.11 Unit 2 Automatic Scram from 100% Power

Unit 2 automatically scrammed from 100% power at 6:07 p.m. on October 5, 1989. A high flux scram signal, average power range monitor (APRM) high-high, occurred due to a 20 psi pressure spike (980 to 1000 psig) when the 86D outboard main steam isolation valve (MSIV) unexpectedly "fast" closed during surveillance testing (ST). ST 1.3-A-2, "Primary Containment Isolation System - Group I - Logic System Functional Test," was being performed to test the MSIV closure logic. The licensee initiated troubleshooting for the cause of the 86D MSIV closure and suspects a failed DC solenoid.

Reactor level decreased on the scram and was recovered by the reactor feedwater pumps. The lowest indicated level was +1 inches. The water level remained above the low level scram setpoint and HPCI/RCIC automatic start, 0 and -48 inches respectively. However, a reactor water cleanup isolation occurred. The licensee initiated review for the cause for this, but suspects it occurred due to high system flow during the reactor pressure decrease.

The main turbine tripped on reverse power and the recirculation pumps tripped on non-vital bus fast transfer. All nine bypass valves opened after the scram and remained open. The "B" EHC pressure regulator was in control prior to the scram due to abnormalities with the "A" pressure regulator. It appears that the "A" EHC pressure regulator took control of reactor pressure causing the bypass valves to remain open. The operators tripped the EHC pumps and the bypass valves closed. Reactor pressure decreased to approximately 500 psig. The licensee valved out the "A" EHC regulator pressure transmitter and began proceeding to cold shutdown using the bypass valves with the "B" EHC regulator in control.

Operator response to the event included implementation of T-100, "Scram," and T-99, "Post Scram Recovery." The scram was reset and an ENS call was made. A licensee management representative (Project Manager) was in the control room at the time of the scram. The Plant Manager and Assistant Operations Superintendent responded and reported to the control room from home. The licensee proceeded to cold shutdown and commenced a short duration outage to troubleshoot and repair the problems with the MSIV and EHC system as well as perform other minor maintenance.

While proceeding to cold shutdown, a half scram was placed on RPS channel "A" at 6:34 p.m., due to inoperable "C" and "E" IRMs. At 3:27 a.m. on October 6, 1989 a local power range monitor (LPRM) (40-33A) associated with the opposite RPS channel spiked causing a reactor scram to occur. There was no control rod motion as all rods were previously inserted in the core. The licensee reset the scram, but left the RPS channel "A" in the tripped condition until 4:45 a.m., when the "E" IRM was repaired, and tested operable.

The inspector was notified at home of the reactor trip and reported to the control room. Post scram recovery, troubleshooting activities and management review were observed. The inspector discussed the scram with the on-shift operators including the Shift Manager and Staff Supervisor. Discussions were also held with licensee management and test personnel. The inspector verified that all rods were fully inserted and that the reactor was shut down. Control room indications, strip chart recorders, computer logs and operator logs were reviewed. The inspector also reviewed the surveillance test, and the T-100 and 99 procedures that were implemented. The draft incident report was also reviewed. The inspector concluded that operator response to scram was normal and in accordance with procedures. The inspector will review the licensee's root cause analysis and adequacy of corrective actions to prevent recurrence when the LER is issued. The inspector had no further questions or concerns at this time.

4.3 Logs and Records (71707)

The inspector reviewed logs and records for accuracy, completeness, abnormal conditions, significant operating changes and trends, required entries, correct equipment and lock-out status, jumper log validity, conformance with Limiting Conditions for Operations, and proper reporting. The following logs and records were reviewed: Control Room Shift Supervisor Log, Reactor Engineering Logs, Unit 2 Reactor Operator Log, Unit 3 Reactor Operator Log, Control Operator Log, STA Log, QC Shift Monitor Log, Radiation Work Permits, Locked Valve Log, Maintenance Request Forms, Temporary Plant Alteration Log, Special Procedures Log, Information Tag Log, Annunciator Mode Log, Plant Status List, and Ignition Source Control Checklists. Control Room logs were compared with Administrative Procedure A-7, "Shift Operations," and the Operations Manual. Frequent initialing of entries by licensed operators, shift supervision, and licensee site management constituted evidence of licensee review. No unacceptable conditions were identified.

4.4 Engineered Safeguards Features (ESF) System Walkdown (71710)

The inspector performed a detailed walkdown of portions of the high pressure coolant injection (HPCI) in order to independently verify the operability of the Unit 2 system. The HPCI walkdown included verification of the following items:

-- Review of documents listed in Attachment 1.

-- Inspection of system equipment conditions.

-- Confirmation that the system check-off-list (COL) and operating procedures are consistent with plant drawings.

-- Verification that system valves, breakers, and switches are properly aligned.

-- Verification that instrumentation is properly valved in and operable.

-- Verification that valves required to be locked have appropriate locking devices

During his walkdown, the inspector noted the licensee identified, via an information tag, that the HPCI mechanical overspeed trip reset function was inoperable. The fact that the overspeed trip would not automatically reset, was identified during a surveillance test. Further licensee and NRC review concluded HPCI was operable. However, further concerns with the licensee's safety evaluation process were identified in this case. These will be addressed in NRC Inspection 277/89-18, 278/89-18.

4.5 Nuclear Review Board (NRB) Meeting

The inspector attended portions of the NRB meeting number 249 on September 7, 1989. The inspector verified that the meeting was conducted in accordance with Technical Specifications and procedural requirements. The prepared agenda was followed and NRB members displayed a questioning attitude and a good perspective of nuclear safety.

5.0 Engineering and Technical Support Activities

5.1 Unit 3 Core Reload (60710)

During preparations for Unit 3 core reload, on or around September 5, 1989, an item was found at core grid location 37-59. It was lying across the upper grid and blade guide and was approximately 1 inch x 7 inches and less than 1/4 inch thick. When personnel attempted to retrieve the object, it fell towards the shroud wall into the core. Several people stated that the object floated as it fell. It was described as rigid, dull, and dark in color, and was made of a light material (thin metal, rubber, or plastic). By the location of the item, it must have come to rest after initial core offload because part of the piece covered an empty fuel cell. In addition, it most likely got to its position sometime during the last month because a complete core search was conducted in August 1989. The licensee spent several days searching for the item and could not locate it. The search was abandoned on September 8, 1989. The unknown object was added to a list of other previously identified objects that also could not be retrieved. General Electric (GE) had prepared a safety evaluation addressing loose parts and corrosion concerns for these items. GE's only recommendation was to retrieve the unknown object if possible. However, senior licensee management concluded further efforts would probably not locate the object and abandoned the search.

The licensee began to reload fuel into the reactor vessel on September 10, 1989. Special procedure (SP-1294, "Plant Conditions Necessary to Reload Fuel - Unit 3," Rev. 0, dated August 23, 1989, was complete prior to moving fuel. During core reload, ST-3.1.2, "SRM Core Monitoring Test," was done daily and ST-12.1, "Refueling Interlock Functional Test," was done weekly. Controlling procedures utilized during core reload were GP-11C, "Reactor Protection System Refuel Mode Operation," and FH-6C, "Fuel Movement and Core Alteration Procedure During a Fuel Handling Outage."

The inspector verified that either a senior licensed operator (SLO) or fuel handling SLO was supervising fuel movements. The reactor operator (RO) was in direct communication with the refueling platform operator and a Core Component Transfer Authorization Sheet (CCTAS) printout was being utilized. Source Range Monitors (SRMs) were being continually monitored by the RO and the inspector verified SRM response.

On September 14, 1989, after the daily SRM test was completed, the "B" SRM was not responding properly. Although there was no fuel movement in that particular quadrant, the count rate dropped from ten counts per second (CPS) to two CPS. The licensee declared the "B"

SRM inoperable and began troubleshooting. Fuel reload continued in the adjacent quadrant as allowed by Technical Specifications (TS).

The licensee determined that the "B" SRM did not drive completely back into the core following the test. The SRM was repaired and declared operable on September 15, 1989. Fuel load was then able to continue in the "B" quadrant.

The core reload was complete and verified on September 20, 1989. During this evolution, the licensee followed appropriate procedures and TS. The inspector noted effective coordination between the control room and the refueling floor.

5.2 Unit 3 Integrated Emergency Cooling Tower Test

On September 24, 1989, the licensee performed an integrated test of the emergency cooling water system. Procedure SP 630-3, "Integrated Test of the Unit 3 Emergency Cooling Water System," Rev. 0, dated September 21, 1989, tested the closed loop capability of the emergency cooling tower using the Unit 3 high pressure service water (HPSW) pump bay and level control system. The inspector reviewed the test procedure and noted no abnormalities. The "B" emergency service water (ESW) pump supplied cooling water to all available emergency diesel generator heat exchanges, both Unit 3 reactor building closed cooling water (RBCCW) heat exchangers, and all ECCS safeguard equipment coolers. Two Unit 3 high pressure service water (HPSW) pumps supplied cooling water to two RHR heat exchangers. The Unit 3 HPSW discharge to the pond valve (MO-3486) was closed to return HPSW to the ECT.

For the test, the licensee needed the services of 15 personnel for most of the day (16 hours). The test went smoothly and no problems were identified. Rated flow for the ESW system (8000 gpm) and HPSW in the emergency cooling mode were demonstrated. The ECW pump backup to the ESW pumps on low ESW header pressure was also demonstrated. The inspector had no concerns or questions regarding the test.

6.0 Review of Licensee Event Reports (LERs)

6.1 LER Review (90712)

The inspector reviewed LERs submitted to the NRC to verify that the details were clearly reported, including the accuracy of the description and corrective action adequacy. The inspector determined whether further information was required, whether generic implications were indicated, and whether the event warranted on site follow-up. The following LERs were reviewed:

LER No. LER Date Event Date	Subject
*2-89-17 09/14/89 08/15/89	Fire watch not established
*2-89-18 09/18/89 08-18/89	Unit 2 rod block logic failure
*3-89-01 08/18/89 07/20/89	Unit 3 reactor building exhaust flow recorder out of service
S-89-03 09/22/89 08/25/89	Bomb threats

6.2 LER Follow-up (92700)

For LERs selected for follow-up and review (denoted by asterisks above), the inspector verified that appropriate corrective action was taken or responsibility was assigned and that continued operation of the facility was conducted in accordance with Technical Specifications (TS) and did not constitute an unreviewed safety question as defined in 10 CFR 50.59. Report accuracy, compliance with current reporting requirements and applicability to other site systems and components were also reviewed.

6.2.1 LER 2-89-17 concerns a licensee identified TS violation (277 and 278/89-22-01). TS 3.14.E.2.a requires a continuous firewatch for the recirculation motor generator set lube oil room when the sprinkler system is out of service. The control room had established an hourly firewatch with the associated room fire detection system out of service. However, the operators failed to recognize that the fire detectors being out of service also placed the sprinkler system out of service. This condition existed for three hours and 35 minutes on August 15, 1989.

The inspector reviewed the LER and determined that licensee corrective actions were adequate. These included posting a continuous fire watch, revising the administrative procedure to provide additional guidance for controlling Technical Specification fire watches in this case, and placing the event description in the required reading. The inspector had no further questions at this time.

6.2.2 LER 2-89-18 concerns a failure to trip the rod block logic of the reactor manual control system as required by TS. The licensee identified a TS surveillance test (ST) inadequacy for tripping rod block logic when the flow variable average power range monitor (APRM) rod block trip settings were nonconservative.

TS Table 3.2.C, Note 10, requires that an inoperable APRM rod block channel be placed in the tripped condition within one hour. This is a licensee identified violation of TS 4.3.C (277/89-22-02).

During the performance of ST 3.3.2, "Calibration of APRM System," Rev. 13, personnel failed to communicate to the Shift Supervisor incorrect settings in the rod block trip logic due to reactor recirculation drive flow indicating higher than actual. The discrepancy was identified and corrected in two hours and 50 minutes.

The inspector reviewed the LER and associated TSs and STs. The APRM rod block remained functional throughout the event, but with a reduced margin between the rod block setpoint and the scram setpoint. Procedure ST 3.3.2 was revised to provide necessary actions, including communications to shift management, when nonconservative APRM rod block settings are determined.

The inspector concluded that the licensee adequately addressed this TS violation.

6.2.3 LER 3-89-01 concerns a licensee identified TS violation (278/89-22-03). TS 3.8.C.4.d requires a flow rate estimate to be made within four hours when both of the Unit 3 reactor building exhaust ventilation flow monitors are out of service. Each monitor provides an input to a dual pen reactor building exhaust ventilation flow rate recorder in the control room. During conduct of special procedure (SP) 1251 on July 20, 1989, power to the 30Y35 panel was de-energized for maintenance which subsequently disabled the flow rate recorder. An oncoming senior licensed operator noted that the recorder was inoperable and determined that a flow estimate had not been done. This condition existed for almost five and one-half hours before a flow estimate was done. Effluent calculations were completed and the results were within limits.

The inspector reviewed licensee corrective actions in the LER and concluded they were adequate. These included satisfactorily performing the flow estimate and effluent calculations, counselling the personnel involved, placing the event description in the required reading, revising the administrative procedure for writing special procedures, and reviewing previous SPs for similar problems (none were found). The inspector had no further questions.

7.0 Surveillance Testing (61726, 71707)

The inspector 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. Parts of the following tests were observed:

-- S12N-60A-APRM-FICW "APRM F Calibration/Functional Check," Rev. 1, dated September 11, 1989, performed on September 28, 1989.
-- ST 23.8, "HPCI Overspeed Trip Test," Rev. 0, dated September 26, 1989, performed on September 27, 1989.
-- ST 21.3, "Adjustment of HPCI Overspeed Trip Reset Time," Rev. 3, dated August 3, 1988, performed on September 26, 1989.

No inadequacies were identified.

8.0 Maintenance Activities (62703)

The inspectors reviewed administrative controls and associated documentation, and observed portions of work on the following maintenance activities:

Document	Equipment	Date Observed
MRF	HPCI Overspeed Trip Device	September 26, 1989

Administrative controls checked, if appropriate, included blocking permits, fire watches and ignition source controls, QA/QC involvement, radiological controls, plant conditions, Technical Specification LCOs, equipment alignment and turnover information, post maintenance testing and reportability. Documents reviewed, if appropriate, included maintenance procedures (M), maintenance request forms (MRF), item handling reports, radiation work permits (RWP), material certifications, and receipt inspections.

No inadequacies were identified.

9.0 Radiological Controls (71707)

During the report period, the inspector examined work in progress in both units, including health physics procedures and controls, ALARA implementation, dosimetry and badging, protective clothing use, adherence to radiation work permit (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.

10.0 Physical Security (71707)

10.1 Routine Observations

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.

During the inspection period, the inspector received an anonymous telephone call regarding a potential concern with PECo security management, including the security shift assistants (SSA), in dealing with the contract security force. The inspector interviewed three SSAs, numerous guards, and PECo security management personnel. No basis for the concern was identified. The inspector also spoke with the PECo security manager and noted he was aware of and had resolved a concern with overtime and time sheet approval. The inspector had no further questions or concerns in this area.

10.2 Illegal Possession of Drugs

The inspector was informed on September 13, 1989, that a Philadelphia Electric Company maintenance employee pleaded guilty to possession of illegal drugs and had been denied access to the site. This action was a follow-up to a 1987 case involving the conviction of several PECo employees and contractors for the possession and sale of drugs.

The individual had been implicated around May 1988, during the drug investigation. At that time, the individual was denied access to the site, drug tested and placed on the Employee Assistance Program (EAP). The individual tested negative and denied any involvement with illegal drugs.

Over the next several months, the employee completed the EAP, passed numerous, random drug tests and was allowed access to the site after lengthy interviews. The individual was closely monitored and randomly drug tested. The individuals' performance was very good during the latter part of 1988 and during 1989. However, during the follow-up investigation, the individual admitted to possession of illegal drugs. Plant access for the individual was denied due to false statements made during the earlier PECo interviews to assess suitability for reaccess. The individual's acceptability for employment will be determined by licensee management in the near future.

10.3 Illegal Drug Found Outside Protected Area

On September 23, 1989, the licensee found 2 to 3 grams of a white powder, determined to be cocaine by a field test, in the vehicle of two contractor employees. The substance was sent off site to a laboratory for confirmatory testing. Both individuals denied that the substance belonged to them. Both individuals were given drug tests and the results were negative. In accordance with their fitness for duty program, the licensee denied site access to both individuals on September 23, 1989, and informed the local law enforcement agencies.

11.0 Assurance of Quality

11.1 Reportability Determination

During this report period, the inspector noted three instances in which there were long delays in evaluating reportability of issues found on Unit 3, and in determining their potential effect on Unit 2. In all three instances (see Sections 4.2.1, 4.2.3 and 4.2.8) nuclear engineering was involved in the reportability evaluation in some manner. In the case of the missing supports on the CAD/CAC systems, four weeks elapsed from the time engineering was aware that the Unit 3 system was inoperable until the site made an ENS call and checked for effect on Unit 2. In the case of questionable Unit 3 Appendix R calculations, it was nearly two and one half months by the time the ENS call was made and Unit 2 applicability was reviewed. Finally, for the non-EQ ECCS motor termination splices, three weeks elapsed before engineering determined the situation to be reportable, and checks were initiated on the similar Unit 2 motors. Even though all three issues dealt with a shutdown unit (Unit 3), they were potential concerns for Unit 2, which was operating.

The licensee acknowledged the inspector's concerns and agreed to examine the reportability link between the site and nuclear engineering to quicken reportability evaluations.

11.2 Effective Work Coordination

Two instances were noted in which there was good communication, coordination and support between different on site groups. During the Unit 3 core reload and vessel reassembly, operations and maintenance worked well together. Also, the technical section and operations effectively ran the integrated emergency cooling tower test for Unit 3.

12.0 Review of Periodic and Special Reports (90713)

The inspector reviewed the following periodic and special reports to verify the information reported by the licensee was technically adequate and satisfied the applicable reporting requirements established in the Technical Specifications, the license, and 10 CFR:

- Peach Bottom Semi-Annual Effluent Release Report No. 27, Revision 1, January 1 - June 30, 1989, dated September 7, 1989.
- Sewage Spill, Noncompliance with NPDES Permit, dated September 14, 1989.
- August 1989 Monthly Operating Report, dated September 14, 1989.

The inspector had no questions or concerns with these reports.

13.0 Management Meetings

13.1 Preliminary Inspection Findings (30703)

A verbal summary of preliminary findings was provided to the Plant Manager, Peach Bottom Station at the conclusion of the inspection. During the inspection, licensee management was periodically notified verbally of the preliminary findings by the resident inspectors. No written inspection material was provided to the licensee during the inspection. No proprietary information is included in this report.

13.2 Attendance at Management Meetings Conducted by Region Based Inspectors (30703)

Date	Subject	Inspection Report No.	Reporting Inspector
09/19-22/89	Operator Exams	89-18/18	Sisco

13.3 Management Meetings

The Peach Bottom SALP Management Meeting was held at the Conference Center on September 18, 1989. The NRC Region I Administrator was present. In addition, the Peach Bottom NRC Restart Panel conducted a meeting with licensee representatives following the SALP Management Meeting. The inspector attended these meetings.