U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No. 50-277/88-18 License No. DPR-44
50-278/88-18 DPR-56

Licensee: Philadelphia Electric Company
2301 Market Street
Philadelphia, Pennsylvania 19101

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

Inspection At: Delta, Pennsylvania

Dates: June 4 - July 15, 1988

Inspectors: T. P. Johnson, Senior Resident Inspector
R. J. Urban, Resident Inspector
L. E. Myers, Resident Inspector
R. A. McBrearty, Reactor Engineer
R. J. Bailey, Physical Security Inspector
J. H. Williams, Project Engineer

Reviewed By: J. H. Williams 7/26/88
J. H. Williams, Project Engineer date

Approved By: James C. Linville Jr 7/26/88
J. C. Linville, Chief, date
Reactor Projects Section 2A,
Division of Reactor Projects

Summary

Areas Inspected: Routine, on site regular and backshift resident inspection (179 hours Unit 2; 189 hours Unit 3) of accessible portions of Unit 2 and 3, operational safety, radiation protection, physical security, control room activities, licensee events, surveillance testing, refueling and outage activities, maintenance, and outstanding items.

Results: Deficiencies were noted in general employee training (section 11.0). Numerous events were caused by personnel errors (sections 4.2 and 12.1). The potential cracking of the Unit 2 access cover manways is resolved (section 4.4.1). Improvements were noted in the system outage turnover process (see section 4.4.4). The Nuclear Review Board changes were reviewed (see section 4.7). Management oversight of operating activities was determined to be good (section 12.2).

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DETAILS

1.0 Persons Contacted

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
J. C. Oddo, Nuclear Security Specialist
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

The unit remained in cold shutdown during the inspection period. System maintenance outages continued during the period. Plant modifications, corrective and preventive maintenance, and system testing were performed.

2.2 Unit 3

The unit remained defueled, and RHR and recirculation pipe installation in the drywell was completed during the inspection period. The reactor vessel was filled to the flange.

3.0 Previous Inspection Item Update (92701, 92702)

3.1 (Closed) Unresolved Item (277/87-09-02; 278/87-09-02). Remote shutdown panels (RSP) inability to achieve cold shutdown condition. The inspector reviewed the FSAR 7.18, Technical Specification 3/4.11.C, and the Safety Evaluation Report. The as built RSPs for both units are consistent with the licensed design. In addition, the 10 CFR 50 Appendix R required alternate shutdown panels (ASP) and related systems to have the capability to achieve cold shutdown. The ASPs and systems will be operable prior to either unit restart. Based on the above, the unresolved item is resolved and closed.

3.2 (Closed) Unresolved Item (277/88-01-02). Unit 2 reactor vessel shroud access hole cover cracking (see section 4.4.1).

3.3 (Closed) Violation (277/86-09-02; 278/86-12-02). Failure to identify and correct degraded conditions of emergency load center transformers E-424, E-234, E-434 and E-334 and emergency cooling tower load center transformers E-13A, E-23A, and E-43A. After the inspector identified the condition, the licensee took prompt action to repressurize the transformers. Plant operator round sheets were revised to include the proper gas pressure acceptance criteria and translation of transformer surface temperature to hot spot temperature. The licensee subsequently wrote surveillance test procedure ST 8.7, "Emergency Transformer Daily Surveillance", Rev. 0, dated 2/5/87 to help assure that transformers are maintained at the proper temperature and pressure. The ST is issued weekly, but performed by the plant operator and reviewed by shift supervision daily. Maintenance Request Forms (MRFs) are written for out of specification readings. The licensee has a goal of repressurizing transformers within 24 hours of finding low gas pressure. The inspector reviewed completed surveillance tests for the weeks of February 2, April 20, July 27 in 1987; March 7, and March 28 in 1988. The tests were adequately performed and based upon discussions with the systems engineer, the licensee appears to be monitoring transformer performance to determine need for repair. The inspector examined the eight emergency load center transformers and found no unacceptable conditions. The licensee indicated in their corrective actions to the violation, plans to repair leaking transformers when load center bus outages occur. On the tour, the inspector noted that E-334 was out of service because of work on the E-33 bus. The bus outage began on March 7, 1988. The MRF files indicated that this transformer was leaking. Discussion with the licensee indicated that their efforts were focused on Unit 2 equipment. The licensee has repaired leaks on E-234 and has plans to repair E-424. Licensee actions to repair other leaking transformers will be followed. Based upon this inspection of licensee actions, this item is closed.

4.0 Operations Review

4.1 Station Tours (71707)

The inspector observed plant operations during daily facility tours. Most accessible areas of the station were inspected.

4.1.1 Control Room and facility shift staffing was frequently checked for compliance with 10 CFR 50.54 and Technical Specifications. The presence of a senior licensed operator in the control room was verified frequently. Operator attentiveness to plant operations was determined to be adequate.

4.1.2 The inspector frequently observed that selected control room instrumentation and recorder traces confirmed that instruments were operable and indicated values were within Technical Specification requirements and normal operating limits. Engineered safeguards features system switch positioning and valve lineups were verified daily based on control room indicators and plant observations.

4.1.3 Selected control room off-normal alarms (annunciators) were discussed with control room operators and shift supervision to assure they were knowledgeable of alarm status, plant conditions, and that corrective action, if required, was being taken. In addition, the applicable alarm cards were checked for accuracy. The operators were knowledgeable of alarm status and plant conditions.

4.1.4 The inspector checked for fluid leaks by observing sump status, alarms, and pump-out rates; and discussed reactor coolant system leakage with licensee personnel.

4.1.5 Shift relief and turnover activities were monitored daily, including periodic backshift observations, to ensure compliance with administrative procedures and regulatory guidance. No inadequacies were identified.

4.1.6 The inspector observed the main stack and both reactor building ventilation stack radiation monitors and recorders, and periodically reviewed traces from backshift periods to verify that radioactive gas release rates were within limits and that unplanned releases had not occurred. No inadequacies were identified.

4.1.7 The inspector observed control room indications of fire detection instrumentation and fire suppression systems, monitored use of fire watches and ignition source controls, checked a sampling of fire barriers for integrity, and observed fire-fighting equipment stations. No inadequacies were identified.

4.1.8 The inspector observed overall facility housekeeping conditions, including control of combustibles, loose trash and debris. Cleanup was checked during and after maintenance. Plant housekeeping was generally acceptable.

4.1.9 The inspector observed the shutdown nuclear instrumentation subsystems (source range and intermediate range monitors) and the reactor protection system to verify that the required channels were operable. The inspector noted that two of the Unit 2 source range monitors (SRM) were indicat-

ing three counts per second. This is the Technical Specification minimum for operability for startup. The inspector discussed this with licensee personnel. The SRM count rate will be reviewed in a future inspection.

4.1.10 The inspector frequently verified that the required off site electrical power startup sources and emergency diesel generators were operable (see section 4.2.6).

4.1.11 The inspector monitored the frequency of plant and control room tours by plant and corporate management. The tours were generally adequate.

4.1.12 The inspector verified on a weekly basis, the operability of selected safety related equipment and systems by in-plant checks of valve positioning, control of locked valves, power supply availability, operating procedures, plant drawings, instrumentation and breaker positioning. Selected major components were visually inspected for leakage, proper lubrication, cooling water supply, operating air supply, and general conditions. No significant piping vibration was detected. The inspector reviewed selected blocking permits (tagouts) for conformance with licensee procedures. No inadequacies were identified.

4.1.13 The inspectors performed backshift and weekend tours of the facility on the following days:

-- June 9, 1988; 5:30 - 6:00 a.m.
-- June 10, 1988; 5:30 - 6:00 a.m.
-- June 11, 1988; 8:00 a.m. - 4:00 p.m.
-- June 25, 1988; 4:00 p.m. - 12:00 a.m.
-- July 11, 1988, 5:00 a.m. - 6:00 a.m.

4.1.14 The inspector verified that the QC shift monitors were performing periodic control room tours.

4.2 Followup On Events Occurring During the Inspection (93702)

4.2.1 Unanalyzed Condition of Cardox Discharge in the Control Room

On June 3, 1988, at 2:14 p.m., the licensee made a four hour report per 10 CFR 50.72b(2)i concerning an unanalyzed condition found while both units were shutdown. This condition is an inadvertent carbon dioxide (Cardox) discharge into the control room which could be caused by a pressurization and subsequent rupture of either control room Cardox hose reel. An

engineering analysis determined that on a Cardox hose rupture, the control room would become uninhabitable in less than two minutes. The licensee determined that the time required for both event recognition and immediate actions for procedure SE-1, "Shutdown from the Emergency Shutdown Panel", may exceed this two minute period. The licensee had previously reported that an engineering evaluation had been undertaken as corrective actions to LER 2-88-08. Future licensee corrective actions include pursuing hardware changes to this Cardox system and/or elimination of this system once approvals are obtained (Technical Specification change). The control room Cardox hose reels were taken out of service. Compensatory fire protection measures include portable extinguishers and equipment both inside and outside the control room.

The inspector reviewed this engineering analysis and evaluation, procedure SE-1, and LER 2-88-08. The inspector also discussed this unanalyzed condition with licensee engineers and operators. The licensee intends to submit an additional LER for this item. The inspector will review the LER and any longer term corrective action in a future inspection.

4.2.2 Unit 2 Shutdown Cooling (SDC) Isolation Actuation on June 4, 1988

At 2:00 a.m., on June 4, 1988, an engineered safeguards features (ESF) actuation occurred when shutdown cooling (SDC) valves MO-17 and MO-18 received an isolation signal. Apparently there was some confusion regarding whether this was an unplanned or planned ESF actuation, and the licensee did not make an ENS call until 3:45 p.m., on June 4, 1988. At the time of the actuation, maintenance and MOVATS testing was being performed on the valves. The permit was "temporarily" cleared and an auxiliary operator closed the breaker feeds to each Limitorque motor. Maintenance was also being performed on SDC logic and therefore the MO-17 and 18 valves received an isolation signal to close. The MO-17 and 18 Limitorque operators were in a condition in which motor rotation had not been checked and the limit/torque switches had not been set. Thus MO-17 was initially closed and it went further closed; and, MO-18 was initially closed and it went open. Both valves experienced some Limitorque operator damage, and MO-17 had some breaker damage. Valve body inspections of both valves were performed. SDC had been out of service since May 31, 1988. The unit was in cold shutdown with

the reactor vessel head off and the cavity flooded. Reactor water temperature was 90 degrees F, and heatup rate was less than one degree F per day at the time of the SDC isolation.

The inspector reviewed the following documents:

- -- Maintenance Request Forms (MRFs) 2-10-F87-10641,2 and associated blocking permit,
- -- Upset Report P-2-88-13,
- -- control room operator logs,
- -- electrical drawings MI-S-23 sheets 27 and 31
- -- "Temporary Clearance of Permits" memo dated 6/6/88,
- -- MO-17,18 "Damage Recovery" memo dated 6/9/88,
- -- MRF 2-56-M88-6163,
- -- M-57.8 performed on MO-17 DC breaker
- -- MRF 2-10-M88-6166 on MO-18 valve
- -- MRFs 2-56-M88-6170, 6169, 6164, on MO-18 AC breaker

The licensee performed the following maintenance, testing, and repair actions to the MO-17/18 valves, operators, motors and breakers:

MO-17

- o replaced Limitorque operator and motor
- o overhauled breaker and replaced overload heaters
- o replaced valve yoke and stem
- o installed new grafoil packing
- o performed MOVATS testing and LLRT

MO-18

- o inbody lapping of seats
- o overhauled breaker and checked overload circuitry
- o replaced valve stem and wedge
- o installed new grafoil packing
- o performed MOVATS testing and LLRT

The inspector attended an event critique meeting on June 7, 1988. At this meeting, the licensee determined that the root cause of this event was poor communication between the work group (MOVATS testing) and the operating shift. Licensee corrective actions include the establishment of a "Temporary Clearance Form"

(T-Clear). This T-Clear form requires the work group to delineate reasons for clearance, component position when unblocked, and known operating constraints. The inspector will review the effectiveness of this corrective action in a future inspection.

No violations were noted.

4.2.3 Unit 3 Engineered Safeguards Feature (ESF) Actuation on June 13, 1988

An unexpected automatic actuation of a Unit 3 ESF system occurred at 3:53 p.m., on June 13, 1988. Two alarms were received in the control room indicating that the reactor water cleanup (RWCU) system had isolated on high system flow. At the time, the RWCU system was blocked out of service. Investigation of the primary containment isolation system (PCIS) logic verified that two RWCU system outside containment isolation logic relays (16A-K60, 16A-K27) were de-energized. These de-energized relays produced the "Group II/III Outboard Isolation Relays Not Reset" alarm. The second alarm, "Cleanup Recirc Pump Suction Line Break," was received and then cleared almost immediately. This alarm can be produced by de-energization of one of two other relays (16A-K63, 16A-K64). Both of these relays were found energized. It was suspected that relay 16A-K63 had momentarily de-energized giving the line break alarm and the RWCU system isolation.

The area around the outside containment high flow switch (DPIS-3-12-124B) was checked to determine if any work was being performed. Electricians in the area were inspecting Class 1E wire splices as part of modification 2355 at the high flow switch. It was determined that one of the high flow switch leads had its insulation worn off. The licensee believes that when the lead was moved, the bare wire touched the metal conduit causing a momentary ground. Relay 16A-K63 de-energized to initiate the isolation and cause the line break alarm. When the ground cleared, 16A-K63 re-energized, clearing the line break alarm.

The licensee reset the isolation and made a four hour Emergency Notification System phone call to the NRC. The worn insulation on the wire was also repaired. The licensee intends to submit an LER for this occurrence.

The inspector reviewed the SLER, preliminary upset report P-3-88-05, control room logs and M-1-5-23, "RWCU Outboard Isolation Logic". In addition, the inspector discussed the event with operations personnel and engineers. The LER will be reviewed in a future inspection.

No violations were noted.

4.2.4 Unit 2 Engineered Safeguards Feature (FSF) Actuation on June 14, 1988

An unexpected isolation of two Unit 2 Group III primary containment isolation system (PCIS) valves occurred at 6:10 a.m., on June 14, 1988. A control room operator placed the A standby gas treatment system (SGTS) fan inservice to increase drywell ventilation flow to help cool the air. A main stack high-high radiation signal was present due to a blocking permit (2-63-8801980) for the system auxiliary trip unit. Once the A SGTS fan was started, the logic for the isolation was complete and both 18" drywell vent valves (AO-2506, AO-2507) closed. The logic that caused the ESF actuation is part of a new modification that is in response to TMI Action Plan Item II.E.4.2.7 (see section 5.0). No other valve movement occurred because they were closed.

The licensee determined that the shift was aware that the stack monitor auxiliary trip unit was blocked but did not understand that a high-high trip was present. The blocking permit did not specify that trips were present.

For corrective action, the licensee secured the A SGTS fan, reset the PCIS relays, verified all automatic actions occurred per design, and made a four hour ENS phone call to the NRC. In addition, a shift meeting was held to discuss the event and that an LER is being prepared. The licensee indicated that training on these changes was scheduled after the modification testing was completed.

The inspector reviewed the SLER, preliminary upset report P-2-88-14, Rev. 1, control room logs, the blocking permit, and associated P&IDs. In addition, the inspector discussed the event with operations personnel and engineers. The LER will be reviewed in a future inspection.

No violations were noted.

4.2.5 Loss of Power to Emergency Response Facilities (ERFs)

During an electrical storm on June 16, 1988, a lighting strike apparently tripped the 33-05 line at 2:25 p.m., and caused a loss of power to the Emergency Operations Facility (EOF) and the Technical Support Center (TSC). Emergency backup power is supplied to these ERFs by a diesel generator located at Unit 1. However, the diesel generator was blocked out of service for maintenance. Normal power was restored at 3:01 p.m., and the licensee made a one hour emergency notification system (ENS) phone call to the NRC at 3:15 p.m. The licensee determined the event was a major loss of emergency assessment capability and was reportable under 10 CFR 50.72(b)(1)(v).

Later that evening, another thunderstorm caused the 33-05 line to be lost at 8:05 p.m. Normal power was restored at 8:30 p.m., and was again lost at 9:00 p.m. Power was finally restored to the ERFs at 9:35 p.m., with no further incidents. The licensee made another ENS phone call at 9:04 p.m., to report both of these events.

For corrective action, the licensee restored normal power to the ERFs. In addition, the Unit 1 diesel generator was returned to service. A suspected licensee event report (SLER) was also submitted.

The inspector reviewed the SLER, control room logs and spoke with control room personnel. The licensee determined that an LER is not required. No violations were noted.

4.2.6 Potential Grid Problems on June 22, 1988

At 1:15 p.m., on June 22, 1988, the PECo load dispatcher informed the control room that electrical distribution grid problems may occur during the period 3:00 - 6:00 p.m. The cause of the potential grid problems was the excessive demand on the PJM (Pennsylvania-New Jersey-Maryland) network due to high temperatures combined with the shutdown of a large nuclear unit during the morning. The control room was informed that grid voltage reductions and "brownouts" were likely.

Plant management informed the inspector of this degraded condition including steps to be taken to minimize the potential loss of off site power. At the time of notification from the load dispatcher, the following power related equipment was out of service for maintenance:

- -- E-2 diesel generator (DG)
- -- E-3 diesel generator
- -- B emergency service water (ESW) pump
- -- Emergency cooling water (ECW) pump

The E-2 DG and the ECW pump could not be made available due to the status of maintenance. The E-3 DG and the B ESW pump were out of service for minor problems. The licensee took actions to return them to service. This included maintenance task completion and testing. Both off site power sources were also available.

The licensee conducted a status meeting at 1:30 p.m. of operations, maintenance, outage planning, health physics, system engineering and management personnel. The licensee discussed equipment status and availability, contingency plans for loss of off site power, staff augmentation for afternoon shift, procedures available for loss of power and recovery, load shifting to ensure continuity of critical systems, operator briefings and procedure walkthroughs, and emergency plan classification. The following procedures were discussed:

- -- SE-11, Station Blackout
- -- S.8.4.F, Cross Connecting 4KV Emergency Buses
- -- S.8.3.K.1, Install Temporary Feed to 480V Emergency Bus Load Centers and Removal
- -- S.8.4.B , Synchronizing and Loading of Diesels
- -- S.8.4.A, Manual Start of Diesels
- -- S.8.4.C, Auto Operation of Diesels
- -- S.8.4.J, Diesel Generator Load Restrictions Under Emergency Conditions
- -- S.8.4.H, Available Loads for Diesels

The inspector attended the control room meeting; reviewed the above procedures; verified that operators were knowledgeable of plant and equipment conditions; performed a walkdown of selected power related systems; attended the 3:00 p.m. shift turnover meeting; and, monitored control room activities during portions of the afternoon shift.

The inspector concluded that the licensee had adequate procedures for loss of power and recovery operations. In addition, the inspector determined the licensee's response to this potential loss of power was good. No unacceptable conditions were noted.

4.2.7 Unit 3 Engineered Safeguards Feature (ESF) Actuation on June 24, 1988

At 10:40 a.m. on June 24, 1988, an unexpected automatic actuation of an ESF system occurred on Unit 3. The drywell and torus instrument nitrogen isolation valves closed as well as the drywell equipment and floor drain isolation valves. All other valves were in closed or blocked positions. The isolation was caused by an individual working on the control room enhancement modification. The front panel of the control panel containing drywell and equipment floor drain control switches were removed for painting. The worker was using a draftman's board with an adjustable T-square to work on the control panel enhancements. When the workers moved the board to go to another location the metal wire guide on the T-square broke. When the tension of the wire was released a control switch grounded. The subsequent ground caused a fuse to blow. The fuse was replaced at 11:00 a.m., the isolation was reset at 11:05 a.m., and an ENS phone call was made at 12:47 p.m. The immediate corrective actions were to cover open control panels with a temporary cover when the panels are off and no work is being done inside of the panel.

The inspector discussed the event with operations and engineering personnel and the worker. The inspector reviewed the SLER, Preliminary Upset Report and control room logs. The inspector will review the LER in a future inspection. No violations were noted.

4.2.8 Unit 2 Shutdown Cooling (SDC) Isolation on July 5, 1988

At 4:06 p.m., on July 5,1988, an unexpected engineered safeguards (ESF) actuation occurred when a shutdown cooling isolation signal was received. The actuation was due to a high pressure signal (75 psig). The RHR pump tripped and shutdown cooling isolation valves MO-17 and 18 closed. At 4:30 p.m., the isolation was reset. Shutdown cooling was placed back in service at 10:04 p.m. The licensee made an ENS call at 7:30 p.m.

The licensee examined the cause of the high pressure signal by determining if the pressure sensor and the associated transmitter were sensitive to vibrations, and they were found to be stable. The Shift Manager received information that three workers were observed in the cable spreading room near the area of SDC logic panels 20C032 and 20C033 when relay 10A-K15 located on 20C033 opened.

The identity and activities of the workers observed were determined and interviewed by Operations Support Group. They were vendor personnel doing verification for a drawing change request of correct relay contact positions. They were supported by a maintenance electrician who was not familiar with the panel or the relays. They had removed covers of relays in the panels to confirm the contact positions. They were replacing covers after verification and found one cover to be difficult to replace. The cover was slightly cocked and when replaced, the contact positions of the relay were heard to chatter. The 10A-K114A relay is energized on low reactor pressure. If the 10A-K114A contacts open, the 16A-K28 relay will de-energize and the contacts will open. This causes a System I and II reactor high pressure shutdown cooling isolation. Apparently, the contacts on 10A-K114A contacts opened when the cover was forcibly realigned.

The vendor personnel were engineers with several months experience at the plant, but did not normally perform field verifications, nor did they understand the importance of these panels. The control room was not notified prior to the opening, entering and relay cover removal.

The inspector reviewed the Suspected Licensee Event Report (SLER), Operation Support Report of the investigation, and discussed the event with operations and engineers. The inspector expressed concern that personnel were working in safety related panels performing inspections without the control room being aware. The licensee agreed and stated that this event's root cause and corrective actions are related to the SDC isolation study submitted to the NRC (see section 4.6). The LER and corrective actions will be reviewed in a future inspection.

No violations were noted.

4.2.9 Degraded Grid Voltage Design Deficiency

The licensee completed a reevaluation of the degraded grid voltage during a loss of coolant accident (LOCA) concurrent with one off site power source being unavailable. Based on this computer aided engineering study, the licensee concluded that electrical bus voltage would drop below the minimum value of 90%. This would occur during sequential starting of the RHR and core spray pump motors. A trip of the one available off

site power source would then occur causing sequential reloading on the diesel generators. A meeting was held with NRR to discuss this subject on July 1, 1988, and the licensee also made an ENS call. Corrective actions are being pursued, and will include design changes and modifications that will require NRC prior approval (including Technical Specification changes). NRR, the region and the NRC resident inspectors will continue to follow licensee actions.

4.2.10 Unit 3 Engineered Safeguards Feature (ESF) Actuation on July 12, 1988

At 10:50 a.m. on July 12, 1988, an unexpected automatic actuation of an ESF system occurred on Unit 3. The drywell and torus instrument nitrogen, and the drywell equipment outside containment isolation valves closed. All other valves in the primary containment isolation system (PCIS) group were closed or blocked. The isolation was caused by a worker placing labels by the valve position indication sockets inside the primary containment isolation system panel during control room enhancement modification work. The worker inadvertently grounded a lead to a socket causing a fuse to blow in the PCIS outside containment group II logic. The fuse was replaced and the isolation was reset at 11:05 a.m.. An ENS phone call was made at 11:53 a.m..

The inspector reviewed the preliminary Upset Report, P-3-88-07, SLER and control room logs. In addition, the inspector discussed the event with operations personnel and engineers. The LER will be reviewed in a later inspection. No violations were noted.

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 lockout 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, and Ignition Source Control Checklists. Control Room logs were compared with Administrative Procedure A-7, Shift Operations. 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 Refueling Outage Activities (60710)

4.4.1 Ultrasonic Nondestructive Examination (NDE) of Unit 2 Reactor Vessel Shroud Access Hole Covers

In January 1988, General Electric Company NDE personnel performed ultrasonic examinations of the reactor vessel shroud access hole covers in Unit 3. Based on the results of the Unit 3 examinations, the access hole covers in Unit 2 were examined during May 28-29, 1988 (NRC Inspection 277/88-13).

Two General Electric Company Level III examiners performed the ultrasonic examination of the Unit 2 covers using a remote ultrasonic fixture which was positioned on the hatch cover plate. The Ultra Image III pulse-echo ultrasonic data acquisition equipment was used for recording examination results, and a video tape recording system was used to record the A-scan with corresponding color C-scan presentation from the Ultra Image III scanning grid.

Calibration of the ultrasonic examination system was accomplished using a full size markup of the access hole cover, including the weld, which contained six notches at various depths (10% to 80% throughwall) in base metal on the cover side. An additional notch, 20% throughwall, was placed at the centerline of the weld.

The following areas were reviewed by the inspector:

- -- QC Traveler HC-1, Revision 0, dated 5/26/88 which documents the results of a visual examination of access cover areas for evidence of loose parts.
- -- Special Process Control Sheet SAHC-A, Revision 0, which provided verification of equipment availability.
- -- Automatic Ultrasonic Calibration Data Sheets C-P6929-1 and -2, which provide calibration information for the 0 degree access cover weld, and the 180 degree access cover weld.
- -- Indication Resolution Sheets R-P6929-1 and 2, which document the evaluation and resolution of indications which were detected in the two access hole covers.
- -- Qualification/Certification records of the two General Electric Company Level III examiners who performed the examinations at Unit 2.

-- Ultrasonic Examination Procedure No. UT-57, Revision 3, "Remote Ultrasonic Examination Procedure for Detection of IGSCC in Shroud Support Access Cover Plate" which governed the ultrasonic examinations at Unit 2.
-- A-scan and C-scan data related to system calibration and the examination of access covers at Unit 2, and other BWR plants where General Electric performed similar examinations.

The resolution sheets documented the detection of weld root geometry indications and entry surface indications in both of the Unit 2 access covers. Similar indications were recorded during the calibration mockup scan in addition to the calibration notch reflections.

Unit 2 examination data were compared by the inspector with data from two similar boiling water reactors which were previously examined by General Electric NDE personnel, and were found to display similar indication patterns with no discernible evidence of cracking.

The inspector ascertained that the two examiners were properly certified to Level III, and had received special training in the use of procedure UT-57 for scanning the access hole covers. In addition, each of the Level III examiners had participated in the EPRI program for detection of IGSCC and successfully completed the practical examination associated with that program.

Examination data were reviewed and evaluated by a team composed of licensee and General Electric Level III staff, and additionally, one EPRI NDE Level III representative. The evaluators concluded that the Unit 2 shroud access covers displayed no evidence of cracking, and were acceptable for continued service. The inspector stated that, based on his review and comparison of data, he agreed with the licensee's evaluation and conclusion.

The unresolved item is closed (see section 3.2) and no violations were identified.

4.4.2 Loose Part Found in Unit 2 Reactor Vessel

Early on June 14, 1988, a health physics technician accidentally dropped a roll of tape into the open Unit 2 reactor vessel. At the time, the steam separator was

installed and preparations were being made to lower the steam dryer in place. During the retrieval process for the roll of tape, a small shiny object was seen on top of the steam separator. Both the tape and object were retrieved.

On June 13, 1988, maintenance personnel were having difficulty latching the #21 shroud head bolt. During efforts to latch the bolt, a light on the service platform went out. During troubleshooting operations, the electrical cabinet supplying power to the light was opened first. After no problems were noted, the light bulb was replaced when it was determined that the bulb had simply burned out.

The shiny object retrieved from the reactor cavity was 1.5" long and had a "tee" handle on the head. The electrical cabinet on the service platform was examined and was determined to be missing one of four "tee" bolts. Apparently, after light bulb troubleshooting activities, the bolt became loose and fell into the vessel. The reason it became loose was due to a missing or faulty rubber locking ring designed to hold the bolt in place.

For corrective action, the licensee performed a visual check of the reactor vessel to determine if any more loose parts were evident; none were found. The service platform was carefully examined to determine if any parts were missing; all parts were accounted for. In addition, maintenance procedures M-4.103, "Service Platform and Support Mechanical Maintenance," and M-4.104, "Service Platform Electrical Maintenance," were reviewed to ensure bolts, fasteners and nuts are secured. To prevent recurrence, the electrical cabinet latches are being drilled and secured with cotter pins. Maintenance request form 8806515 has been initiated to perform the work.

The inspector reviewed the fuel floor log, maintenance procedures M-4.103 and M-401.4 and a June 16, 1988, maintenance engineering group field report (MEGFR001-DSF). The inspector also had discussions with operations and maintenance personnel. The inspector had no further questions and no violations were noted.

4.4.3 Unit 3 Reactor Pressure Vessel (RPV) Fill

The licensee began the filling of Unit 3 RPV on July 5, 1988, after completion of the installation of the large recirculation and RHR piping. Fill was performed in accordance with procedure SP-1052, "Unit 3 Reactor Pressure Vessel Fill," Revision 0. RPV fill was completed on July 8, 1988, with level remaining at 195" reference (at the RPV flange). The inspector reviewed SP-1052 implementation and discussed it with operators. No unacceptable conditions were noted.

4.4.4 Unit 2 System Outage Work

The licensee continues to perform maintenance (MRFs) during system outage windows. The inspector had previously expressed concerns regarding system readiness and testing following maintenance for the A loop of core spray (NRC inspection 277/88-13). Weaknesses identified included check-off-lists (COL) and P&IDs not being updated prior to system testing and turnover.

The inspector reviewed the licensee's completion of maintenance for the A loop of RHR, and subsequent testing and turnover. This review included a walkdown of the system (see section 4.5) and a review of the "System Window Turnover Checklist". This checklist included the following:

- -- review of work completed (MRFs),
- -- operations verification form review,
- -- modifications completed,
- -- blocking permits,
- -- procedures reviewed,
- -- area housekeeping and cleanliness,
- -- component labelling,
- -- system COL and lineups, and
- -- testing and system operability.

Based on this review of the A loop of RHR, the inspector concluded that the licensee has improved the process for completion of Unit 2 system work. No unacceptable conditions were noted.

4.5 Engineered Safeguards Features (ESF) System Walkdown

The inspector performed a detailed walkdown of portions of the residual heat removal (RHR) system in order to independently verify the operability of the Unit 2 A loop. The RHR walkdown included verification of the following items:

-- 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

-- Verification that control room switches, indications and controls are satisfactory.

-- Verification that surveillance test procedures properly implement the Technical Specifications surveillance requirements.

No unacceptable conditions were noted.

4.6 Shutdown Cooling (SDC) Isolations

As requested in NRC Inspections 277,278/87-22 and 277,278/87-25, the licensee responded to a concern with respect to the number of SDC isolations. The NRC requested the licensee to analyze the root causes and to provide corrective actions to reduce the frequency of these isolations.

The licensee responded to this request in letters dated January 11, February 26, and June 9, 1988. In addition, an independent investigation was performed by an evaluation team dated February 23, 1988. The licensee reviewed thirteen SDC isolations that occurred between July 1987 and December 1987. (These SDC isolations have been formally documented by an LER and reviewed in an NRC Inspection Report.) The licensee root cause analysis determined that there were eight related causal factors. These factors are as follows:

1. Design concern in that single loss of power will result in SDC isolation.
2A. Job site work controls, procedures and supervision, were not sufficient to prevent actions leading to SDC isolations.
2B. Procedures for "short term" work (e.g. troubleshooting) lacked sufficient guidance to prevent the inadvertent SDC isolations.

2C. The scope of job planning and review for work performed on site often did not identify potential problems which might be encountered in the course of the work.

2D. There was a lack of specific criteria to be used during the independent review of "temporary" changes.

2E. There is a lack of human factors reviews in the job planning or design process.

3A. There was a lack of hands on training on equipment for personnel who will be responsible for troubleshooting equipment.

3B. Clearly defined lines of authority/responsibility either did not exist or were not known, which would enable personnel responsible for the performance of a task to know the proper interface relationships that must be established in order to safely accomplish the task.

Licensee corrective actions included the following:

1. Review logic design by July 31, 1988; and

2A. Guidance to ensure personnel are cognizant of adjacent circuits when working; and

2B. Increased supervision awareness as to the consequences of work in safety related panels; and

2C. Revision to administrative procedures A-41, "Procedure for the Control of Safety Related Equipment" and A-7, "Shift Operations" when reapplying a permit; and revision to "Rules for Permits and Blocking"; and

2D. Additional drawings and documents available for control room operators by July 29, 1988; and

2E. Revised A-3, "Procedures for Temporary Changes to Approved Procedures; and

2F. Revised instructions and training for electrical field engineering personnel; and

2G. Reviewed panels for flexible conduit interferences; and

2H. Routine test (RT) RT-9.16 to be written by July 31, 1988, which would require panel condition checks after a major outage; and

2I. Revise A-42, "Procedure for the Control of Temporary Plant Alterations" to include temporary electrical feeds; and

2J. Instructions for painting activities in the vicinity of safety equipment; and

2K. Warning signs placed on control panel doors which contain SDC circuits; and

3A. Perform troubleshooting related training for personnel involved in control cabinet work by September 2, 1988; and increase scope of job orientation training for control cabinet work by August 19, 1988; and

3B. Performance of on-scene job reviews by first line supervision for work in panels.

The NRC requested the licensee to provide additional information regarding the link between the causal factors and corrective actions. For causal factors 2A-2E above, the following corrective actions apply:

Causal Factor	Corrective Actions
2A	A, I, J, B, F, H
2B	C, E, I, D
2C	D, A, C, G, H, J
2D	C, E, J
2E	K, G

The inspector reviewed the licensee's correspondence, and reports, including the above causal analysis and corrective actions. Specific corrective actions were verified complete. Future actions and overall effectiveness will be reviewed in a future inspection. The inspector also discussed the topic of SDC isolations with operators, crafts and management personnel. Since January 1988, three SDC isolation signals have been initiated. In two cases SDC was out of service prior to the actuation of the logic signal.

In conclusion, once requested by the NRC, the licensee performed a good root cause analysis review. Corrective actions taken to date appear to be effective in reducing SDC isolations. This item will be reviewed in future inspections.

4.7 Nuclear Review Board (NRB)

The licensee has reconstituted the NRB including the addition of three senior consultants. The NRB Charter and procedures have also been revised. NRB Charter (Revision 11) and Technical Specification (TS) 6.5.2 (Rev. 132/135 dated June 27, 1988) reflect the new reporting functions and membership. The NRB now reports to the Executive Vice President, and the NRB meets periodically with Chairman of the Nuclear Committee of the Board.

The new membership of the NRB includes three consultants. Their experience includes a variety of industry expertise. Procedure NRB-1, "Review Practices," delineates the appropriate area(s) of expertise for each NRB member and alternate.

The inspector reviewed the TS change, the revised NRB charter, NRB procedures 1 thru 5, and NRB commitments made in the Restart Plan Section I (parts 4.1, 4.2 and 4.3). The inspector verified that these changes have adequately been implemented in the NRB charter and associated procedures. In addition, the inspector verified that these items were being performed.

The inspector attended portions of the NRB meeting #222 which was held at Peach Bottom on July 14, 1988. The inspector reviewed the agenda; verified that an NRB quorum was present; and, verified that the meeting was held in accordance with the NRB charter, NRB procedures, and TS 6.5.2.

The inspector concluded that these changes and enhancements in the NRB appear to be beneficial.

5.0 TMI Action Plan (TAP) Item II.E.4.2.7

TAP item II.E.4.2.7 requires containment ventilation and purge isolation valves to close during containment inerting or deinerting when high radiation is detected.

A modification (MOD 664) was made by adding a signal from the main stack radiation monitors to the control circuit for the containment ventilation and purge isolation valves. The high radiation trip is armed only when containment purge valves AO 2506 (3506) and AO 2507 (3507) or AO 2511 (3511) and AO 2512 (3512) are open on Unit 2 (3), respectively, and there is flow through the standby gas treatment system (SGTS). This logic ensures that the trip signal will affect only the unit that is purging through its SGTS.

In a May 7, 1986 letter from the NRC to the BWR Owner's Group, it was stated that lines of 2" diameter or less need not be isolated on a radiation signal. The following valves will now close as part of this modification:

Valve Number Unit 2 (3)	Description
AO 2505 (3505)	Drywell Purge Supply
AO 2519 (3519)	Drywell Purge Supply
AO 2520 (3520)	Drywell Purge Supply
AO 2521A (3521A)	Torus Purge Supply
AO 2521B (3521B)	Torus Purge Supply
AO 2506 (3506)	Drywell Purge Exhaust
AO 2507 (3507)	Drywell Purge Exhaust
AO 2511 (3511)	Torus Purge Exhaust
AO 2512 (3512)	Torus Purge Exhaust

For the review, the inspector reviewed modification package 664, "High Rad Trip of Containment Vent and Purge Valves"; NUREG-0737, "Clarification of TMI Action Plan Requirements"; Technical Specifications; electrical schematic diagrams M-I-S-23, "Primary Containment Isolation System (PCIS); and General Procedure GP-8.B, "PCIS Isolation Groups II and III," Rev. 4, [illegible]13/88.

The inspector determined that the modification is functional on Unit 2. However, the modification acceptance test (MAT) has been started but is not complete. It will be completed prior to Unit 2 restart. The Unit 3 modification is not yet finished and the MAT will be completed prior to Unit 3 restart. The inspector noted that a Technical Specification change for this modification had not been submitted as required by NUREG-0737. The inspector found several areas in the Technical Specifications that are affected by this modification. The inspector discussed this with licensing and operations personnel.

TAP Item II.E 4.2.7 is resolved and closed. However, MOD 664 remains open pending MAT completion on both units, training for operators, and resolution of a possible Technical Specification change. The inspector will review this in a future inspection.

6.0 Review of Licensee Event Reports (LERs) (92703)

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
*88-S04 May 31, 1988 May 2, 1988	Alcohol bottle found in the [illegible]ol room
2-8[illegible]05, Rev. 01 Ma[illegible] Ap[illegible]	Unacceptable containment local leak rate
2-8[illegible] Ma[illegible] Ap[illegible]	Core spray system blown fuse

*2-88-10 June 3, 1988 May 6, 1988	RWCU isolation due to improper block
*2-88-11 June 13, 1988 May 12, 1988	Shutdown scram due personnel error during surveillance testing
*3-88-02 June 3, 1988 May 7, 1988	RWCU isolation due to breaker trip
*3-88-03 June 16, 1988 May 20-22, 1988	ESF actuations due to RPS alternate power supply trip

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 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 88-S04 concerns a Safeguards event where a peach brandy bottle was found in the control room on April 14, 1988. This event was reviewed in NRC Inspection 277/88-10, 278/88-10. No inadequacies were noted relative to this report.

6.2.2 LER 2-88-10 concerns a RWCU isolation that occurred when a fuse was pulled de-energizing isolation logic. The event was reviewed in NRC Inspection 277/88-13. No inadequacies were noted with this LER.

6.2.3 LER 2-88-11 concerns a personnel error causing a shutdown scram during the conduct of a surveillance test. This event was reviewed in NRC Inspection 277/88-13. No inadequacies were noted with this LER.

6.2.4 LER 3-88-02 concerns a RWCU isolation caused when a non-vital breaker tripped for an unknown reason. This event was reviewed during NRC Inspection 278/88-13. No inadequacies were noted with this LER.

6.2.5 LER 3-88-03 concerns ESF actuations of containment isolation logic on May 20 and 22, 1988, caused by trips of the RPS alternate power supply. These events were reviewed in NRC Inspection 278/88-13. No inadequacies were noted with this LER.

7.0 Surveillance Testing (61726)

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. Parts of the following tests were observed:

-- ST 8.3, "Station Battery Quarterly Check," Rev. 15, 5/13/88, performed on June 27, 1988.
-- ST 13.21, "Emergency Cooling Tower Functional Test," Rev. 10, performed on July 14, 1988.

No inadequacies were identified.

8.0 Maintenance Activities (62703)

8.1 Routine Observations

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

Document	Equipment	Date Observed
M-4.601	Replacement of the Shroud Head Bolts	June 13, 1988
MOD 2371	ESW pipe replacement 2D core spray room	June 17, 1988
M4.414	RPV head piping installation	June 21, 1988

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.

In addition, a review of the following completed maintenance procedures was performed:

M-4.103, "Service Platform and Support Mechanical Maintenance"
M-4.104, "Service Platform Electrical Maintenance"

No inadequacies were identified.

8.2 Electrical Safety

On June 8, 1988, at the 8:30 a.m. shift manager meeting in the control room, the inspector learned of an event that occurred on June 8, 1988. During this event, non-licensed operators accidentally brushed a live feed causing a momentary ground that resulted in a flash.

At 5:20 p.m., on June 8, 1988, a plant operator and a floor foreman received a blocking permit for the #2 13 KV auxiliary bus outage. The first step in the permit was to apply a station safety ground (SSG) on the 480 volt side of load center transformer 2G4. The non-licensed operators opened the door of the de-energized compartment and took a voltage reading with a hot stick. The men decided not to place the SSG in this compartment because they could not find a clear place on the feed bus bars other than the braided portion to ground the transformer. The adjacent compartment was opened and a voltage test was performed on both the 480 volt transformer feed and the energized 2G4 bus bars. No voltage response was seen at either, but the men were aware that the 2G4 bus bars should be energized. When the floor foreman attempted to apply the SSG to the C phase of the transformer feed, the energized bus bar was brushed resulting in a momentary ground with a flash. The floor foreman was not injured (he was wearing high voltage gloves) and 2G4 was not affected.

For immediate corrective action, further application of SSGs in 480 volt compartments was terminated pending investigation of the incident. Also, all shift managers were notified of the incident so that the information could be relayed to their respective shifts.

The operations shift reviewed the event, and wrote a "near miss" report and an incident report. Interviews with the two operators were also conducted. The licensee determined that there were several important points brought out during the investigation of this incident: 1) there was no convenient place to attach the SSG to the transformer feed in the specified compartment; 2) the non-licensed operators deviated from the location specified in the blocking permit; 3) non-licensed operators are confused as to whether SSGs can be applied to braided portions of transformer feeds; 4) non-licensed operators are not sure of the required voltage range for hot sticks; and 5) the basis for including the SSG in the blocking permit is not clearly understood.

The licensee proposed four follow-up items to prevent recurrence of this type of incident. First of all, the need to apply an SSG for a similar situation in the future must be determined. If the SSG is needed, a modification should be done to provide a convenient place on transformer feeders for the SSG placement. If they are not needed, permit writers should be notified so that they will not be placed on future permits. Second, electrical training on proper SSG application and the use of safety equipment should be provided. In particular, the issue of placing SSGs on braided portions of a transformer feeder should be resolved. Third, a determination should be made to decide if better equipment is available for non-licensed operators to test for energized 480 volt buses and if additional electrical safety equipment should be purchased. Finally, the involved non-licensed operators should be counseled on the need to strictly adhere to blocking permits. This last item was completed on June 14,1988.

The inspector spoke with operations and electrical personnel, reviewed the incident and near miss report, and examined the 2G4 bus and supply transformer. The inspector noted the braided portions of the 480 volt transformer feeds and the lack of a convenient spot to place the SSG. In addition, the flash damage to the C phase of load center 2G4 was observed. The inspector expressed concerns over the use of an SSG for this type of a block and the confusion that exists concerning the use of hot sticks for voltages less than 1,000 volts (some non-licensed operators might believe the source is not energized).

The inspector concluded that electrical safety training and safety equipment is weak (see NRC inspection 277/88-13; 278/88-13, section 8.2). The inspector will continue to follow this area.

9.0 Radiological Controls (71707, 71709)

9.1 Routine Observations

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.

9.2 Key Control to Locked High Radiation Doors (Allegation RI-87-A-0145)

In late 1987, locked high radiation area key control was taken away from operations personnel because doors were found unlocked and tighter radiation protection controls were being instituted. On December 21, 1987, the resident inspectors were informed by licensed and non-licensed operators that key control and access to locked high radiation areas hampers operators from doing their job in a timely manner and could impact safety during an emergency situation. Through discussions with operators, the inspectors heard of instances where delays of several hours had occurred in entering locked high radiation areas.

During the six month time period since licensee management became aware of the operator concerns, a committee was formed to develop a resolution to this problem. A committee of operations personnel and health physics personnel was formed to determine a solution to key control of locked high radiation areas. Members of the group consisted of several senior non-licensed operators, the superintendent of operations, and the applied health physics supervisor.

At the time of this report, most of the details have been worked out between the operations group and the health physics group. Frequently used locked high radiation area keys will be returned to operations personnel after they have completed a special health physics training program to ensure they are familiar with good health physics practices to adequately protect themselves. The locked high radiation area key control program will be fully covered under a new procedure that will be written in the near future.

For this review, the inspector spoke with committee members and operations personnel, and reviewed health physics procedure HP-109, "Locked High Radiation Area Access Control," Revision 1, dated 8/28/87. The inspector determined that the proper level of management is represented on the committee so that the program will receive proper attention for completion. In addition, the Operations Superintendent stated that he wanted the program to be functional before Unit 2 restart. The inspector stressed that it would be advantageous since the number of locked high radiation areas will increase after Unit 2 returns to power operations.

The inspector determined the allegation to be substantiated. However, since resolution of the key control issue is progressing adequately as described above, the allegation is closed. The inspector will continue to follow this issue until the program is fully functional.

9.3 Contaminated Water Spill

On June 14, 1988, a non-licensed operator ran a temporary drain line from t e reactor cavity pit to a floor drain on the 195 foot elevation of the reactor building. That floor drain is normally used for flushing the standby liquid control (SLC) system and is only connected to a 55 gallon drum located on the 165 foot elevation. The non-licensed operator thought that the particular floor drain was connected to the radwaste system.

During routine decontamination efforts of the reactor cavity pit with high pressure demineralized water, the contaminated water draining from the pit began filling the 55 gallon drum. Shortly thereafter, the contaminated water began spilling on the 165 foot elevation and also backed up the floor drain and spilled on the 195 foot elevation. At approximately 2:00 a.m., on June 15, 1988, health physics was notified that contaminated water had spilled onto the 195 foot and 165 foot elevations in the reactor building. By the time the spill was finally noticed and stopped, approximately 75 gallons of contaminated water had spilled.

The licensee immediately roped off the area as contaminated, took contamination and airborne surveys, and began decontamination efforts later that morning. The area was successfully decontaminated by late afternoon on June 15, 1988. To prevent recurrence, the floor drain was labelled to be used only for SLC flushing. Apparently the sign that used to be posted at the floor drain was removed and not replaced after painting was done in that area.

The inspector toured both affected elevations the morning of June 15, 1988, and noted the roped off areas and decontamination efforts. The inspector spoke with health physics and operations personnel. No one was contaminated from the spill and there were no releases to the environment. The inspector reviewed pre and post decontamination "Radiation-Contamination-Airborne" surveys. Contamination levels were low and post-decontamination values were acceptable. The inspector verified that a sign was posted near the SLC flushing floor drain.

The inspector concluded that health physics did a good job in containing and decontaminating the areas. The inspector had no further questions and no violations were noted.

10.0 Physical Security (71707, 71881)

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.

10.2 Safeguards Event Report June 19, 1988

At 5:20 p.m., on Sunday, June 19, 1988, a contractor supervisor found six unopened Budweiser beer bottles in a contractor break area within the protected area. Security was notified and conducted a search of the area and nothing further was found. All associated contractor personnel were removed from the protected area pending an investigation. At 6:10 p.m., the licensee made an ENS call based on contraband found in the protected area. The senior resident inspector was also notified at home. The licensee's investigation determined that a contractor worker had brought iced tea to work in these beer bottles inside a small cooler. The licensee verified this by sampling each bottle. At 7:35 p.m., the licensee downgraded this event to a loggable event and a subsequent ENS call was made. The contractor employee was interviewed by security management personnel. In conjunction with a review by site management personnel, the employee was allowed to return to the protected area.

On June 20, 1988, the inspector reviewed security and operations logs regarding this event. In addition, the security shift assistant's (SSA) report, the shift manager's report, and the SLER were reviewed. The inspector also examined the six beer bottles and their contents. The inspector concluded that the contents of each bottle was sweetened iced tea. The inspector questioned security personnel with regards to the basis for readmitting the individual who brought these beer bottles into the protected area. The licensee stated that the individual was interviewed by security management personnel. The licensee concluded that he used poor judgment; however, there was no intention of deception. The inspector had no further questions.

No violations were noted.

10.3 Fitness for Duty Policy

PECo made a press release announcement on June 20, 1988, that a new strong and comprehensive drug policy will be implemented. This policy will provide for random testing of all employees (including contractors) who are granted unescorted access to its nuclear facilities. In addition, the new policy will require the mandatory termination of any employee found selling, distributing or using drugs on PECo property. The PECo chairman and chief

executive officer stated that there is zero tolerance for drugs in the work place. The effective date of this new drug policy was July 1, 1988. The initial random drug testing is currently scheduled for August to September 30, 1988.

The inspector reviewed this new policy and discussed it with selected personnel. Site management issued a letter to all personnel on June 21, 1988, delineating the new policy. The inspector will continue to follow the implementation of the revised policy.

10.4 Safeguards Event Report July 9, 1988

At 7:00 p.m., on July 8, 1988, the Unit 3 drywell head was lifted in preparation to complete the fill of the reactor cavity. There was a failure to post a guard for this containment access until 6:00 p.m. on July 9, 1988, when a worker recognized the situation and informed security. A guard was immediately posted, a search was made of the area and nothing abnormal was found. The licensee made a one hour ENS call at 6:46 p.m., and the resident inspector was informed by telephone.

The inspector reviewed the licensee's preliminary report and discussed this with security personnel. The Safeguards Event Report will be reviewed in a future inspection.

11.0 General Employee Training (GET)

On June 8 and July 6, 1988, the inspector attended the annual GET requalification training course. Several deficiencies were identified as follows:

- The Restart Program and associated commitments were not covered.
- The "Tell It To the Manager/Vice President" program was not covered.
- Recent organizational and personnel changes were not mentioned.
- The new corporate ALARA program and the ALARA suggestion program that awards prizes for effective suggestions were not discussed.
- There was no mention of the recently implemented hot particle program.
- Recently implemented administrative procedures delineating radiation worker responsibilities, A-110, and how to report radiological deficiencies, Radiological Occurrence Reports, A-110, were not mentioned.
- Radiation workers were not instructed in their responsibility to report promptly conditions that could lead to a violation and to prevent unnecessary exposure.

-- Radiation workers were not instructed on how to obtain radiation exposure reports.
-- No information was given about changes in Health Physics procedures, such as changes in frisking policies, posting, the use of general and specific Radiation Work Permits, and other procedures that directly impact the radiation worker.
-- Instruction concerning prenatal radiation exposure consisted of handing out the NRC Regulatory Guide 8.13 for later reading, with no instruction, or guidance on how to report a pregnancy.

The inspector reviewed the lesson plan, LP-GET-REQL, Rev. 2, implemented May 1, 1987. The lesson plan references, procedures and administrative limits are no longer in effect. In view of the many changes in procedures, the lesson plan should be revised. The inspector interviewed the Senior Instructor for GET and the Supervisor of General Training. The Supervisor of General Training is filling three supervisory positions in the Training Section. With this workload, the supervisor may not be providing adequate management oversight and review of GET. The inspector noted that in a previous inspection in December 1987, some of these deficiencies and issues were addressed (see NRC Inspection 277/87-29, Section 12.0). A study by a contractor in September 1987 to improve and revise the radiation protection aspects of GET have not been implemented. A manpower request by the supervisor has not been acted upon to revise, administer and maintain the GET program.

In view of previously identified deficiencies in this area, prompt management attention is needed in this area. Pending that review, the GET program is unresolved (50-277/88-18-01; 278/88-18-01).

12.0 Assurance of Quality

12.1 Engineered Safeguards Features (ESF) Actuations Caused by Personnel Error

The inspector noted that during this period numerous ESF actuations occurred due to personnel errors. These actuations are summarized as follows:

Date	Root Cause
6/4	inadequate communication (operator - worker)
6.13	electrician working in control panels - inattention to detail
6/14	inadequate knowledge (operator)
6/24	painter working in control panels - inattention to detail

7/5	engineer working in control panels - lacking knowledge
7/12	painter working in control panels - inattention to detail

These ESF actuations were reviewed in detail by the licensee (see section 4.2) and some causal factors are related to the review that the licensee performed as discussed in section 4.6 of this report. The effectiveness of the licensee's corrective actions will be reviewed in a future inspection.

12.2 Management Oversight of Operations Activities

The inspector noted that there was good oversight of operations activities demonstrated by plant management. Examples of these are:

(1) Response to grid problems on June 22, 1988 (see section 4.2.6).
(2) Follow-up to shutdown cooling isolation (SDC) and resultant damage on June 4 - 7, 1988 (see section 4.2.2).
(3) Follow-up to the numerous SDC isolations (see section 4.6).
(4) Unit 2 system turnover and testing (see section 4.4.4).

13.0 In-Office Review of Special Reports

The inspector reviewed the following:

-- Peach Bottom Annual Radiological Environmental Report No. 45, May 1988.
-- Peach Bottom 1987 Annual Modification Report, dated June 30, 1988.

No unacceptable conditions were noted.

14.0 Unresolved Items

Unresolved items are items about which more information is required to ascertain whether they are acceptable violations or deviations. An unresolved item is discussed in section 11.0.

15.0 Management Meetings

15.1 Preliminary Inspection Findings (30703)

A verbal summary of preliminary findings was provided to the 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.

15.2 Attendance at Management Meetings Conducted by NRC Management and Region Based Inspectors (30703)

Date	Subject	Inspection Report No.	Reporting Inspector
6/6-10/88	QA/QC - Procurement	88-19/19	Napuda
6/27/88	Tour of Plant	N/A	Murley
6/27-30/88	Security	88-18/18	Bailey
7/11-22/88	Maintenance	88-17/17	Gray

15.3 Security Management Meeting on June 9, 1988

The inspector attended a management meeting in NRC Region I (King of Prussia, PA) on June 9, 1988, to discuss security plan implementation concerns. These concerns were associated with the licensee's completion of their internal allegation follow-up and report, and the results of a security audit. Increased oversight of the security force appeared to be necessary and the licensee responded in subsequent letters. This area is the subject of a specialist inspection (277, 278/88-23).

15.4 Station Review Monthly Meeting on July 12, 1988

The inspector attended the monthly station review meeting on July 12, 1988. This meeting is attended by all station management personnel and is conducted by the PECo Executive Vice President-Nuclear. The inspector determined that this meeting was a thorough review of station activities and schedules.