U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/90-14 50-278/90-14	License Nos.	DPR-44 DPR-56
Licensee:	Philadelphia Electric Company Peach Bottom Atomic Power Station P. O. Box 195 Wayne, PA 19087-0195		
Facility Name:	Peach Bottom Atomic Power Station Units 2 and 3		
Dates:	July 3 - August 13, 1990		
Inspectors:	J. J. Lyash, Senior Resident Inspector R. J. Urban, Resident Inspector L. E. Myers, Resident Inspector		

Approved By: L. T. Doerflein   9/12/90

L. T. Doerflein, Chief   Date
Reactor Projects Section 2B
Division of Reactor Projects

Areas Inspected:

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

TABLE OF ACRONYMS

ALARA	As low as reasonably achievable
AO	Abnormal operation
APRM	Average power range monitor
CST	Condensate storage tank
DDFP	Diesel driven fire pump
EAL	Emergency action level
EIC	Event Investigation Coordinator
EIF	Event investigation form
EOP	Emergency operating procedure
ESF	Engineered safety feature
ENS	Emergency notification system
F	Fahrenheit
GE	Group Evaluator
HPCI	High pressure coolant injection
MG	Motor generator
MRF	Maintenance request form
MSIV	Main steam isolation valve
MVP	Mechanical vacuum pump
PCV	Pressure control valve
PORC	Plant Operations Review Committee
RCIC	Reactor core isolation cooling
RPS	Reactor protection system
RPV	Reactor pressure vessel
RWP	Radiation work permit
ST	Surveillance test
TCF	Troubleshooting control form
TS	Technical Specifications
TS LCO	Technical Specification limiting condition for operation
UE	Unusual event

EXECUTIVE SUMMARY
Peach Bottom Atomic Power Station
Inspection Report 90-14

Plant Operations

Rapid operator response, investigation, and quick corrective action in response to the 'A' recirculation pump MG set speed transient on July 6 prevented a scram on Unit 2 (Section 2.1).

Licensed operators did not follow procedures on three different occassions. The first example was an improper reset of a control room high radiation isolation. The second example was improper line-up of the mechanical vacuum pump that led to a release of radioactive gas through the reactor building vent stacks following the July 27 scram. The third example was failure to log the 3 'B' reactor recirculation loop temperature during cooldown following the July 27 scram (Sections 2.2 and 2.5, 50-277/NV4 90-14-01).

A Shift Manager inappropriately bypassed procedural controls during troubleshooting by disassembling the Unit 3 RCIC inverter (Section 2.3).

Response to the July 27 scram was mixed. It appears that the licensee may have had two previous opportunities to identify and correct the potential failure of the automatic PCV that caused the event. Immediate operator response (fast power reduction and manual scram) was good. The Shift Manager missed the declaration of the UE due to an unclear EAL. Root cause and corrective action for the failure of the #4 breaker to trip was good. The system for tracking RPV thermal/hydraulic transients to ensure continued validity of the licensee's analyses appears to be lacking and will remain unresolved (Section 2.5, UNR 277/90-14-02).

Maintenance and Surveillance

Lack of adequate test prerequisites to ensure acceptable torus and river water temperatures before performing the routine HPCI monthly ST caused the operating crew to enter an EOP unnecessarily (Section 3.0).

The diesel driven fire pump was blocked out of service using a Troubleshooting Control Form rather than a blocking permit. As a result, during disassembly of the pump discharge check valve, water spilled onto the floor due to an improperly positioned valve (Section 4.0).

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DETAILS

1.0 PLANT OPERATIONS REVIEW (71707, 92702)

1.1 Operational Overview

As the inspection period began, both reactor units were operating at 100% power. Unit 2 power was reduced to 95% on July 6, 1990, to improve the efficiency of the condensate demineralizers in removing copper from the feedwater. Unit 2 remained at 95% power until July 17 when copper concentrations in the feedwater decreased to less than 0.3 parts per billion. Power was increased to 100% and remained there through the end of the inspection period.

Unit 3 remained at 100% power until July 27 when an unplanned manual scram occurred due to loss of condenser vacuum caused by the isolation of the off-gas system. The unit was restarted on August 1 after repair of the off-gas system and some limited undervessel work. The unit returned to full power on August 6 and remained there until the end of the period, except on August 11 when a brief power reduction to 80% was made to repair the 'C' reactor feedwater pump.

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

The inspector completed 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 103 total hours of on-site backshift time.

1.2 Event Investigations Review

On June 25, 1990, a Unit 3 main generator runback occurred due to low stator water cooling pressure (see NRC Combined Inspection Report 277/278 90-13). On July 7, 1990, the Unit 3 reactor core isolation cooling system was declared inoperable when its Topaz inverter was damaged during troubleshooting activities (see Section 2.2).

Neither of the events were reportable to the NRC, but both required initiation of an event investigation under Nuclear Group Administrative Procedure (NGAP) NA-02A002, "Investigation of In-House Events." The inspector requested a copy of each event investigation form (EIF) a significant period after the event, and they could not be located for several days.

Both EIFs were initiated by the appropriate operations shift group evaluator (GE) when the events occurred, but were temporarily lost within the PECo organization. NA-02A002 requires forwarding the original EIF to the appropriate Superintendent, who determines if a full or partial investigation is warranted. The EIF is then forwarded to the Event Investigation Coordinator

(EIC) for reviewer assignment. However, there is not a time limit identified in NA-02A002 for this portion of the process. In both instances, the EIFs hadn't been promptly forwarded to the EIC for disposition. Therefore, delays in processing the events were encountered.

To correct the problem in the near-term, a letter was written by the EIC to the operating shift GEs requiring them to forward the original EIF directly to the EIC. NA-02A002 will be revised to reflect this requirement as well as other enhancements to improve the process.

2.0 FOLLOW-UP OF PLANT EVENTS (93702, 37700, 90712, 40500)

2.1 Unit 2 'A' Reactor Recirculation Pump Speed Transient

On July 6, 1990, at 2:50 p.m. with Unit 2 at 95% power, a 1/2 scram occurred due to high reactor power detected by the 'B' and 'D' APRM channels. The shift crew responded rapidly to the transient, making preparations for a possible full scram and attempting to determine the cause. The 'A' reactor recirculation pump had momentarily increased to maximum speed and returned to normal. Reactor power peaked near 120% due to the increase in recirculation flow. The APRM scram set point is also about 120%. Due to the slight normal deviation in APRM response, only the 'B' and 'D' APRM channels tripped. The 1/2 scram was reset and the MG set fluid coupler scoop tube for the recirculation pump was locked into position.

It had been previously noted that the Bailey scoop tube positioner allowed the pump speed to vary slightly as the temperature in the MG set room and outside ambient air temperature increased. The area ventilation system was recently affected by placing a security barrier over the supply intake opening, decreasing the volume of supply air due to the constriction.

The licensee removed the exterior panels from the Bailey scoop tube positioner electronics cabinet and attached a multichannel recorder to monitor various components. No unusual values were found. Additional monitoring will be performed when ambient temperatures increase. In the meantime, the scoop tube was unlocked to allow proper operation of the recirculation speed runback logic, and the mechanical stop was set to limit any transient speed increase demanded by the controller to 30-35 RPM over nominal. The cabinet panels will remain off to improve cooling until the problem is resolved. The inspector had no further questions at this time.

2.2 Control Room Ventilation Isolations

Once on July 7, 1990, twice on July 18, 1990, and again on July 30, 1990, the control room ventilation system isolated and transferred to the emergency ventilation mode. The ESF actuations were due to spikes in the 'B' control room ventilation intake radiation monitor. The isolations were reset and normal control room ventilation was restored after each of the actuations. However, on July 30 the operating shift reported during the ENS notification that the normal ventilation fans were found energized after the actuation. These fans should trip when the ventilation system realigns to the emergency mode. The operating shift did not realize that when the control room radiation monitor channels are reset, the normal ventilation fans will restart if action is not taken to secure them prior to the reset. System operating procedure (SO) 40D.7.A, "Restoration of Control Room Ventilation Following a High Radiation Trip," Revision 1, states to place the six normal ventilation fans to the 'off' position prior to resetting the isolation. The operator performed the reset incorrectly, without use of and adherence to the procedure. The inspector informed the licensee that this failure to follow procedures constitutes a violation of Technical Specifications (277/NV4-90-14-01). The Assistant Superintendent of Operations issued a letter to the shift crews stressing the importance of following procedures and the proper method of resetting a control room ventilation isolation.

IE Bulletin 80-06, "Engineered Safety Feature (ESF) Reset Controls," dated 3/13/80, required modification of safety-related equipment to prevent equipment automatic return to its normal mode following reset of the ESF actuation signal. The licensee committed in the Bulletin response to establish effective procedural controls in lieu of modifying this system. However, based on interviews with licensee operations and technical personnel it appears that over time the reason for this procedure requirement was lost. Other procedural commitments were made in the response, and may warrant additional review. This area will be reviewed as part of the violation follow-up.

Spiking by the 'B' control room radiation monitor has been a recurring problem. Numerous attempts to repair the monitor have been unsuccessful. A replacement monitor was procured near the close of the inspection period. During installation, a dirty connector to the high voltage power supply was found which may have caused the spikes. The new monitor didn't fit correctly, and the old monitor was left in place.

2.3 Unit 3 RCIC Inverter Failure

On July 7, 1990, with Unit 3 operating at 100% power, electrical system engineers were troubleshooting a battery ground. The instrument being used was inadvertently grounded to the panel cabinet, causing the RCIC Topaz inverter supply fuse to blow. The fuse was replaced and blew again. The RCIC system was declared inoperable at 1:45 p.m. and its TS LCO was entered. TS allow reactor operation for seven days provided the HPCI system is proven operable. ST procedure 6.5-3, "HPCI Pump, Valve, Flow, Cooler," was successfully performed.

The Shift Manager initiated a MRF to repair the RCIC Topaz inverter at 1:55 p.m. The MRF was assigned a priority 2 code which means that immediate attention is not required, and work can be scheduled in a controlled, expedited manner. The Shift Manager then went to the cable spreading room with the Shift Technical Advisor to troubleshoot the inverter by measuring voltages, disconnecting an electrical plug and lifting two leads. They also removed the inverter from its support panel and removed its cover to examine the internals. They identified a failed diode and carried the inverter to the control room. By the time the MRF had been approved and was ready for turn over to I&C personnel for performance of work, the inverter had already been disconnected, removed, and transported to the control room.

Administrative Procedure (A)-42.1, "Temporary Circuit Modifications During Troubleshooting of Plant Equipment or Verification of Equipment Operability," states that a Troubleshooting Control Form (TCF) shall be used when lifting or pulling leads. However, the procedure states that if troubleshooting is required immediately as determined by shift supervision, A-42.1 need not be used. In addition, A-42.1 states that troubleshooting may include minor repairs, but relay replacement or disassembly of devices is to be performed under a MRF. Procedure A-26, "Corrective and Preventive Maintenance Using CHAMPS," states that the MRF shall be complete through section 4 before equipment is blocked, and turned over for performance of work.

The inspector spoke with the Shift Manager concerning the events surrounding this incident. He stated that in his opinion, immediate troubleshooting was required and use of the A-42.1 process was not required. The inspector concluded that a 7 day TS LCO does not warrant bypassing the A-42.1 controls. However, A-42.1 is vague as to what constitutes the need for immediate troubleshooting. Several other procedures are also vague in this area. To clarify this issue, a letter was written by the Operations Superintendent to all Shift Managers describing the circumstances that justify emergency departure from administrative procedures. The long-term fix will be inclusion of this guidance in the PORC approved Operations Management Manual.

Once the inverter was properly turned over to I&C, a diode and several transistors were found damaged. The diode was obsolete, therefore a replacement evaluation was performed. Since repair of the inverter could not be guaranteed prior to expiration of the 7 day TS LCO, PECo performed a replacement part evaluation to replace the obsolete inverter with a newer model. In addition, an engineering work request (A0001998), a nonconformance report (P900431) and a 10 CFR 50.59 review were performed. The new inverter was installed and the RCIC system was satisfactorily tested and declared operable on July 11.

The inspector reviewed appropriate licensee documents and found them to be complete and accurate. Installation of the invertor was observed and was carried out in accordance with appropriate procedures.

2.4 Intermittent Loss of a Safety-Related Battery Charger

On July 24, August 3, and twice on August 4, 1990, the 2B battery charger experienced a transient which caused an undervoltage condition on the HPCI system 250 VDC bus. In each case the charger output current decreased to zero for a short period, ranging from about one to five minutes. Without the charger supplying the bus, the safety-related batteries continued to supply power to energized DC system loads. DC system voltage dropped to below the low voltage alarm setpoint, alerting the control room operator of the condition. In each case the Shift Manager declared the battery inoperable due to the loss of the charger and the lower than normal system voltage. The affected DC bus supplies motive power for HPCI system components, B core spray logic power, and a portion of the E2 and E4 emergency diesel generator start logics. As a result these systems were also declared inoperable and the NRC was informed of each event via ENS. Since the charger resumed operation within several minutes no plant shutdown was actually initiated.

Follow-up investigation by the licensee identified that the transients were caused by degradation of a foam rubber support piece necessary to secure the charger plug-in control unit modules firmly in their slots. Loss of foam elasticity over time allowed a module in the charger current control loop to loose contact periodically. The licensee replaced the foam rubber associated with the 2B charger. Recently the licensee procured a spare charger assembly. The Nuclear Engineering Department is designing a seismically qualified, Class IE mounting and installation configuration to allow this spare to be easily moved among the electrical equipment rooms, and tied in as a direct replacement for any permanently installed charger. Additionally, procedures are being developed to address inspection and replacement of the foam rubber support piece for the remaining chargers. The preventive maintenance program has also been revised to include periodic reinspection of the support.

Battery current/voltage curves generated during the most recent service test were reviewed to assess whether the observed voltage drop was consistent with the applied load. Overall results of service and performance tests completed on the battery since its installation about five years ago were also reviewed to determine the general condition of battery performance. No concerns were identified.

2.5 Unit 3 Scram Due to Loss of Recombiner Cooling Water

2.5.1 Sequence of Events

On July 27, 1990, at 3:50 a.m., the Unit 3 off-gas trouble alarm was received when the off-gas recombiner system isolated. In addition, the off-gas hi and hi-hi radiation alarms were received. This condition is a specific Unusual Event (UE) Emergency Action Level (EAL). But a UE was not declared at that time. Main condenser vacuum was steadily decreasing and a fast power reduction was initiated. Thirteen minutes into the event, the Shift Manager directed the operator to scram the reactor from 80% power.

The main turbine was manually tripped and due to a faulty breaker, power was lost to the #4 13 kV bus. In addition, a tie breaker inadvertently left in the test position precluded energizing one 480 V load center.

RCIC was started in the CST to CST mode. When the last feedwater pump was tripped, RCIC was used to inject water into the vessel but was unable to maintain level. HPCI was manually started to supplement RCIC and was subsequently placed in the CST to CST mode after reactor water level returned to normal. Some radioactive gas was released through the Unit 3 vent stack due to loss of the loop seal on the recombiner. Reactor pressure was reduced below 600 psig at which time the condensate pumps were used to inject water into the vessel. A UE was declared at this time due to the off-gas spike received 48 minutes earlier. The UE was terminated 22 minutes later.

Operators began preparations to place the mechanical vacuum pump in service, but due to improper valve lineup and pressurization of the main condenser through the MSIV drain valves, radioactive gas was released into the turbine building and out of the Unit 2 and 3 vent stacks. In addition, condenser pressurization caused excessive turbine seal steam to be exhausted by the steam packing exhausters into the main stack, which caused an off-gas stack high radiation alarm.

After about 4 hours, plant conditions stabilized and the unit proceeded to a cold shutdown condition. At about 350 psig reactor pressure, the idle 'B' recirculation loop experienced a heatup of greater than 100 degrees F per hour due to a sudden occurrence of reverse flow. Each of the issues discussed above are addressed in more detail below.

2.5.2 Recombiner Isolation

The recombiner outlet stream passes through a single condenser, cooled by discharge flow from the main condensate pumps. The condensate passes through a pressure control station consisting of three parallel flow paths prior to entering the condenser. Two of the flow paths contain an automatic pressure control valve (PCV) which senses downstream pressure via a bourdon tube, and transfers tube deflection to the pneumatic controller via mechanical linkage. The third flow path contains a manual gate valve. Station operating procedures indicate that one PCV is in service, the second PCV is isolated and the manual bypass valve is closed. Unit 3 was aligned in this configuration prior to the transient.

The transient initiating event was failure of the inservice PCV linkage connecting the bourdon tube to the controller. Failure of the linkage caused the valve to close, removing cooling water to the condenser and resulting in closure of the steam jet air ejector discharge valves.

Following the event the licensee found that the Unit 3 standby PCV linkage had failed in a similar manner. Inspection of the comparable Unit 2 valves identified that one of the two PCVs also had failed linkage. It appears that pressure fluctuations in the downstream piping are being sensed by the controller and causing fatigue failure of the linkage. The licensee is pursuing possible modification of the pressure control system to address this design problem. Until a permanent solution is finalized the licensee has isolated the air supply to the inservice Unit 3 PCV and manually throttled the valve to provide the correct outlet pressure. The pressure will be monitored and the valve periodically adjusted.

In discussion with the responsible system engineer the inspector learned that Unit 2 had been operating for an indeterminate period of time with both PCVs isolated, and pressure control maintained by manually throttling the bypass valve. This configuration is not consistent with the system operating procedure, and may indicate that there was an awareness by the operating staff of the PCV design weakness. The inspector also reviewed MRF 8504977 initiated in 1985 because of failure of one of the Unit 2 PCVs due to pressure pulsations. The MRF was completed in 1987, and included installation of two flow snubbers in the pressure sensing line to dampen the pulsations. A similar modification wasn't implemented on Unit 3, and the Unit 2 modification apparently wasn't effective as evidenced by the additional failure. The inspector questioned whether the alternate Unit 2 valving alignment and the Unit 3 MRF/modification represent previous opportunities to identify and address the problem. Sufficient information was not available to make a clear determination.

2.5.3 Declaration of Unusual Event

Immediately following the off-gas system isolation the off-gas stream radiation monitor spiked by more than 500 mr/hr, and an off-gas high radiation alarm was received in the control room. The duration of the spike was less than one minute and the readings returned to normal quickly. The Shift Manager was aware of the spike and alarm at the time but didn't consider it to represent a significant safety concern. No actual off-gas radiation increase had occurred, the spike was due to the buildup of gas in the piping system near the detector following the isolation. About 48 minutes after the spike the Shift Manager recognized that while the spike may not have represented a true increase in off-gas radiation levels, its occurrence along with the off-gas high radiation alarm was a specific EAL for declaration of a UE. Based on this a UE was declared and was subsequently terminated a short time later.

The intent of this EAL is to provide early recognition and notification of fuel failure. Fuel failure would result in a significant, persistent increase in radiation levels. Because the spike associated with this transient was clearly not fuel failure related, the procedural direction to declare the UE was not recognized by the Shift Manager. The Superintendent of Operations discussed the incident with all the Shift Managers and is drafting a revision to the EAL to clarify its intent and application.

2.5.4 #4 Breaker Failure

When the reactor and main turbine tripped, power was lost to the #4 13 kV bus. The #4 breaker (General Electric Type AM) was powering the bus from the Unit 3 auxiliary transformer and should have opened automatically allowing the #14 breaker to close and energize the bus from offsite power. The breaker didn't automatically trip and repeated attempts to trip the breaker manually from the control room were unsuccessful. An operator was dis-patched to the breaker and saw smoke emanating from the cubicle. Attempts to trip the breaker locally were unsuccessful. The breaker was finally tripped by using a screwdriver on the trip mechanism.

MRF 9005268 was initiated to repair the breaker. The trip coil was burned up and it was replaced. A General Electric service representative was brought onsite for assistance. The problem was traced to alignment of the trip armature linkage to the trip latch. There was enough free play in the linkage such that when the trip coil energized, the linkage operated but didn't pull on the trip latch. Since the travel of the coil is only between 1/16 and 3/16 of an inch, no linkage play can be allowed. The sensitive adjustment of the linkage was not detailed in the vendor manual. In addition, the manual trip lever was adjusted such that extraordinary force was required to trip the mechanism and the grease inside the trip latch roller was hard and sticky. This breaker had not been overhauled since 1985 and was due for preventive maintenance in October, 1990.

The manual trip lever was readjusted and the latch roller was disassembled, cleaned and relubricated. Maintenance procedures were revised and personnel were trained on various breaker adjustment techniques by the vendor representative. A record search was initiated to determine if other breakers in the plant might be in a similar condition. The investigation was still in progress at the close of the inspection. The PM frequency was revised to once per cycle, and will include cleaning, adjustment and relubrication.

2.5.5 Tie Breaker in Test Position

When control room operators were restoring 480 V load centers from the #3 13 kV bus to the #4 13 kV bus, it was discovered that tie breaker 4-3G4 was in the test position. Therefore, nonsafety-related bus 4G4 had no power, even though control room breaker lights indicated that it was connected to the #3 13 kV bus.

On June 6, 1990, the 4-3G4 tie breaker was tested in accordance with a system operating procedure. The breaker is placed in the test position, checked, and then racked back in before use. Records did not reveal any other manipulations of this breaker prior to July 27. No clear root cause could be determined for the out of position breaker. However, this is an example of an equipment status control problem.

2.5.6 Alignment of the Mechanical Vacuum Pump (MVP)

Following the off-gas isolation and manual plant scram, operations personnel attempted to reset the recombiner isolation and restore main condenser vacuum. The cause for the recombiner isolation wasn't readily apparent. As a parallel path to reestablishing condenser vacuum, shift management directed that the MVP be prepared for operation, but not placed in service. System operating procedures establish the normal MVP valve alignment with the condenser suction valves closed. However, prior to the event the valves had been opened to help improve air ejector performance, and had been listed on the Abnormal Equipment Status List. Abnormal Operating Procedure (AO) 8.2-3, Revision 0, "Off-Gas System Operation During Controlled Shutdown if High Off-Gas Activity Exists," provides the sequence of actions needed to prepare the MVP for service. The procedures assumes implementation starting from a normal valve lineup and calls for the operator to: 1) place MVP seal purge in service; 2) start the MVP; 3) crack open one vacuum breaker for a maximum of five seconds, and 4) crack open the MVP suction valves from the main condenser for a period of five seconds and then close them. The operator then monitors the main stack radiation monitor for response prior to reopening the suction valves.

During the evolution the Shift Supervisor became concerned that placing the system in service in the sequence established in the AO would cause the water in the vacuum breaker loop seal to be drawn into the MVP, possibly causing damage. Because of this concern the shift deviated from the instructions in the AO and opened the vacuum breaker before closing the MVP suction from the condenser and prior to starting the MVP. It was not recognized at the time that the condenser was at a slight positive pressure. When the vacuum breaker was opened the positive condenser pressure forced the loop seal water and noncondensable gases out into the turbine building. This resulted in contamination of the area, creation of a turbine building airborne radioactivity problem, and the exhaust of the noncondensable gas through the plant vent. It appears that AO 8.2-3 adequately addressed the situation facing the operators, and if it had been followed the release would have been prevented. The inspector informed the licensee that failure to use and adhere to the approved procedure for this evolution constitutes a violation of NRC requirements (NV4 277/90-14-01).

2.5.7 Vent and Main Stack Off-Site Release

During this event there were three releases of radioactive materials from the Unit 2 and 3 reactor building vents and the main stack. The total release represented a very small fraction of the TS instantaneous dose rate and quarterly release limits.

The first release was from the Unit 3 reactor building vent due to the recombiner isolation. The elevated recombiner pressure caused the offgas loop seal to blow out into the radwaste building. The radwaste building ventilation exhausts to the Unit 3 reactor building vent. This caused a brief spike at 4:45 a.m. that reached a maximum of 40,000 counts per minute (CPM).

At 6:15 a.m. the main stack radiation monitor increased briefly to 288 counts per second. The steam packing exhauster, which discharges directly to the main stack, continued to run following the plant trip. The slight pressurization of the condenser combined with the operating exhauster caused the minor increase in radiation monitor readings.

The last release was from the Unit 2 and 3 reactor building vents, when the MVP was being prepared for service as described above. Most of the radioactive material was exhausted through the Unit 3 reactor building vent, but since the turbine buildings are not isolated some was drawn into the Unit 2 reactor building vent. This release occurred at 6:50 a.m. resulting in a brief increase to 80,000 CPM on the Unit 3 vent stack radiation monitor.

The inspector examined the unit vent stack and main stack recordings. Procedures and calculations were reviewed for methodology and accuracy in calculating estimates of instantaneous dose rates and quarterly dose assignments due to gaseous releases and were found to be technically sound. The inspector had no further questions.

2.5.8 Heatup of the B Reactor Recirculation Loop

During the cooldown on July 28, the B recirculation loop experienced an excessive heatup as indicated by the loop suction temperature recorder. The B reactor recirculation MG set had tripped following the scram and hadn't been restarted. With the reactor at 350 psig, the operators attempted to heat up the idle loop by opening the recirculation pump discharge valve to establish reverse flow. No reverse flow occurred since the speed of the A recirculation pump couldn't be increased above the speed limiter. Therefore, reactor depressurization was continued in order to reduce the temperature of the A recirculation loop. The A loop temperature was being monitored every 15 minutes as required by TS, but the B loop was not. When reactor pressure reached 50 psig, reverse flow suddenly initiated and the B loop temperature rose from 105 to 266 degrees F in 18 minutes.

General Electric performed an evaluation of the heatup and conservatively classified the event as an improper start of an idle recirculation loop. Nuclear engineering performed a review and determined that continued operation was permissible. The vessel is analyzed for 5 events of this type with significant margin for extending the analysis for occurrence of additional similar events. The licensee believes that one additional event of this type has previously been experienced. However, the program for tracking such occurrences is weak, so that a confirmatory review is warranted. ST 12.4, "Reactor Pressure Vessel Transients - Cycles Record," tracks various thermal/hydraulic events, but not improper idle recirculation loop starts. Certain other types of events for which the analysis specifies a limit are also not tracked. The licensee is working to revise the system and update the data. A historical review of recorder charts and logs may be required. This area will remain unresolved pending completion of the licensee's review (50-277/UNR 90-14-02).

ST 9.12, "Reactor Vessel Temperatures," requires logging both recirculation loop temperatures during heatup and cooldowns every 15 minutes to satisfy TS 4.6.A.1. However, the idle loop temperature was not logged during the cooldown because the operator believed it was not necessary since the recirculation pump was not running. A similar occurrence was the subject of LER 3-90-003 issued on April 5, 1990. Corrective action at that time consisted of placing a note in ST 9.12 reminding the operators to log all temperatures. The operator did not read the ST prior to its use, but only used the table in the procedure to record the temperatures. This is another example of failing to follow procedures (50-277/90-14-01).

Corrective actions to prevent future idle loop heatup events and to ensure adequate temperature data collection will consist of procedure enhancements. However, several weeks after the event the involved procedures had not been revised. The inspector stressed the importance of instituting immediate corrective actions where warranted, rather than waiting for the completion of the formal event investigation.

2.6 Unit 3 HPCI Inoperable

On August 4, 1990, during surveillance testing, the HPCI system was declared inoperable when the turbine stop valve would not stay open. Unit 3 was at 85% power and a 7 day TS LCO was entered.

Licensee investigation determined that the overspeed trip device was malfunctioning. A spring internal to the trip mechanism didn't have enough force to keep the trip plunger seated. The trip plunger was floating up and down allowing control oil to bleed from the system to the sump intermittently. This caused the stop valve to cycle.

The spring adjustment stop nut was found tight. The procedure used to adjust the spring requires a spring force of between 1.5 to 5.0, pounds with the auxiliary oil pump running. The spring force was set at 3.5 pounds in late 1989. The as-found force was less than one pound. The licensee believes that decreased oil leakage past the trip plunger due to swelling of the tappet assembly allowed additional pressurization below the plunger, thereby reducing the net spring force. The spring force was increased to 3 pounds. The HPCI system was satisfactorily tested and was returned to service on August 5.

The overspeed trip device on HPCI systems are susceptible to swelling and binding. As a short-term fix, General Electric recommended that smaller trip plungers be used. This modification was previously done for both units. An improved model will be installed on both units during their next scheduled outages. In the interim routine stop valve and HPCI flow surveillance testing already being implemented by the licensee appear adequate to address this issue.

3.0 SURVEILLANCE TESTING OBSERVATIONS (61726, 71707)

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

On July 20, 1990, the inspector observed performance of ST 6.5F-2, "HPCI Pump, Valve, Flow, Cooler." Due to HPCI exhaust steam input to the torus, water temperature began to rise. Since the initial torus water temperature was 88 degrees F, little margin existed before mandatory entrance into an EOP was required (95 degrees F). One loop of torus water cooling was in service as required by the procedure. However, since the river temperature was warm (about 78 degrees F), heat transfer was insufficient.

By the middle of the test, torus water temperatures were already in the low 90s. A second loop of torus water cooling was added but temperatures continued to rise. When 95 degrees F was reached, TRIP procedure T 102, "Primary Containment Control," was entered. Appropriate procedure steps were followed, the ST was completed, torus water temperature was reduced, and the TRIP procedure was exited.

ST 6.5F-2, as well as three other HPCI STs, don't consider the torus water temperature prior to test initiation. In addition, river water temperature and the number of torus water cooling loops and heat exchangers to be placed in service is also not considered. The inspector discussed his observations with the Operations Support Engineer, who agreed that entrance into an EOP during routine testing was not desirable. Changes to the STs are being considered.

4.0 MAINTENANCE ACTIVITY OBSERVATIONS (62703, 71707)

The inspectors reviewed administrative controls and associated documentation, and observed portions of work on a sample of maintenance activities. No concerns, except those discussed below, were identified.

On August 1, 1990, during performance of ST 6.17, "Diesel Driven Fire Pump (DDFP) Operability Test," the engine overheated. The cause was attributed to blockage of a "Y" strainer on the engine cooling water inlet with clam shells.

On August 7, a MRF was written to disassemble and inspect the DDFP basket strainers and pump discharge check valve. The licensee used a TCF to block the DDFP. Apparently the TCF procedure didn't specifically prohibit blocking systems in this manner. However, the inspector concluded that blocking the DDFP by using a TCF did not provide an adequate level of control. A blocking permit should have been used to establish the appropriate isolation. The test connection isolation valve was left opened by a non-licensed operator, in accordance with the TCF. When the cover to the check valve was unbolted, water from the test connection began spilling onto the floor. An operator manually closed the valve to stop the spill. A properly reviewed blocking permit most likely would have prevented the water spill.

The inspector spoke to operations and maintenance personnel concerning the observation. It appears that revised TCF procedure A-42.1, issued near the close of the inspection period, wouldn't allow the use of a TCF in this manner.

5.0 RADIOLOGICAL CONTROLS (71707)

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

The inspector observed individuals frisking in accordance with HP procedures. A sampling of high radiation area doors was verified to be locked as required. Compliance with RWP requirements was verified during plant tours. 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.

6.0 PHYSICAL SECURITY (71707)

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

7.0 MANAGEMENT MEETINGS (30703)

7.1 Commissioner Rogers' Plant Tour

On August 13, 1990, NRC Commissioner Rogers, his Technical Assistant Gail Marcus, and Region I Administrator Thomas Martin toured Peach Bottom. Following the tour the licensee conducted a presentation focusing primarily on maintenance and chemistry program status and initiatives.

7.2 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the Peach Bottom Station Plant Manager 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.

7.3 Management Meetings Conducted by Region Based Inspectors

The following inspector exit interviews were attended during the report period:

Dates	Subject	Report No.	Inspector
7/23-27	Diesel Generator Annual Inspections	90-15/15	Woodard

ATTACHMENT I

Facility and Unit Status

Unit 2

July 3	Reactor at 100% power
July 6	Power reduced to 95% due to high feedwater copper values
July 15	Reactor power increased to 100%, feedwater copper values improved to less than 0.3 ppb
July 16-August 13	Reactor power at 100%

Unit 3

July 3 - 26	Reactor at 100% power
July 27	Manual scram following isolation of the off-gas system
July 28 - 31	Unit shutdown for minor repairs
August 1	Mode switch to startup and reactor critical
August 2	Generator is synchronized to the grid
August 3 - 5	Reactor power ascension
August 6 -10	Reactor power at 100%
August 11	Reactor power reduction to 80% to repair high vibration on the 'C' reactor feedwater pump
August 12 - 13	Reactor at 100% power