U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/90-17 50-278/90-17	License No.	DPR-44 DPR-56

Licensee: Philadelphia Electric Company
Peach Bottom Atomic Power Station
P. O. Box 195
Wayne, PA 19087-0195

Facility: Peach Bottom Atomic Power Station Units 2 and 3

Dates: August 14 - September 24, 1990

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Areas Inspected:

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

EXECUTIVE SUMMARY
Peach Bottom Atomic Power Station
Inspection Report 90-17

Plant Operations

The control room staff responded quickly and effectively to a Unit 2 electro-hydraulic control system fluid leak. Shift and operations management implemented a conservative and well planned approach to the shutdown (Section 2.4).

The Shift Supervisor released a work activity involving battery charger maintenance without complete consideration of the effect, and of previously established Plant Operations Review Committee guidance related to the activity. Additionally the licensee event report describing the event was not complete (Section 2.2, UNR 90-17-01)

Maintenance and Surveillance

The surveillance procedure used for calibration of the 125 VDC battery charger low voltage alarms did not include the correct battery voltage operability limits, and included steps which, as described in PORC Position Paper 35, would result in entry in Technical Specification 3.0.C Section 2.2, UNR 90-17-01).

The licensee implemented a leak repair to the packing of a Unit 2 main steam isolation valve (MSIV). The repair was performed without use of an approved ASME Code repair plan. This deficiency was identified by the licensee and is being addressed (Section 4.4).

During the period two problems with calibration and performance of reactor vessel water level instrumentation were identified by the licensee. Contributing to the problems were improper initial calibration of two instruments, and failure of daily instrument channel checks to identify the problems promptly (Section 3.0, NV 90-17-03).

The high pressure coolant injection (HPCI) system auxiliary oil pump failed to start during a routine surveillance test due to a faulty contactor. The contactor, along with several other HPCI and reactor core isolation cooling system electrical components had not been previously included in the licensee's preventive maintenance program (Section 2.7).

Poor communication and a procedure weakness contributed to a reactor water cleanup system isolation (Section 2.5).

Engineering and Technical Support

The licensee has classified all valve packing and gasket material as nonsafety-related. The inspector questioned the acceptability of this practice for cases where the packing forms part of the primary containment leakage boundary (Section 4.4, UNR 90-17-05).

The licensee demonstrated effective communication and prompt follow-up in response to concerns raised at Limerick regarding the qualification of flood and high energy line break (HELB) penetration seals, and control of HELB vent paths. However, the good performance in this case is tempered by the fact that an engineering work request questioning the qualification of the flood seals had been initiated about four months earlier. The inspectors will review the licensee's completed analysis of the HELB barrier controls during a future inspection (Section 4.3, UNR 90-17-04).

During conduct of a licensee high pressure service water (HPSW) SSFI the licensee discovered that a loss of instrument air could lead to failure of the HPSW and emergency service water pumps due to loss of pump room ventilation. The inspector questioned why the design deficiency had not been identified during the licensee's review in response to Generic Letter 88-14 (Section 2.9, UNR 90-17-02).

Assurance of Quality

Licensee management response to a spectrum of events and issues during the period consistently displayed a conservative, safety oriented approach. Problems were well reviewed and corrective actions taken were generally effective.

The licensee's quality assurance and maintenance departments worked together to better understand a series of recent maintenance performance problems, similar to the MSIV repair process weakness noted above. QA subsequently issued a Corrective Action Request to track this issue.

The licensee is implementing a series of safety system functional inspections (SSFI). These inspections represent a significant commitment of resources by the licensee and are effective in establishing and evaluating the system design basis. This effort will be complemented by the planned design basis document reconstitution program (Section 2.9).

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DETAILS

1.0 PLANT OPERATIONS REVIEW (71707)

The inspector completed NRC Inspection Procedure 71707, "Operational Safety Verification," by directly observing activities and equipment, touring the facility, interviewing and discussing items with licensee personnel, independently verifying safety system status and limiting conditions for operation, reviewing corrective actions, and examining facility records and logs. The inspectors performed 52 total hours of on site backshift inspection, including 8 hours of deep backshift and weekend tours of the facility.

At the beginning of the inspection period, both units were at 100% power. Unit 2 reactor power was reduced to 50% on August 22 for a control rod pattern adjustment. A main steam isolation valve (MSIV) packing leak and high copper levels in the feedwater continued to limit power to between 50% and 80%. On August 30 the unit was shutdown due to inoperable water level instruments on the 2B condensing chamber and reference leg. The unit was restarted on September 4 but was shut down from 26% power on September 6 when a fluid leak was found in the electro-hydraulic control system. Unit 2 was restarted on September 8 and reactor power was limited to 80% during the rest of the inspection period due to high feedwater copper levels.

Unit 3 reactor power was reduced to 65% on August 17 to repair condenser tube leaks. Reactor power reached 100% on August 20 and remained there until September 6, when power was again reduced to 45% to repair leaking condenser tubes. Reactor power reached 100% on September 14 and remained there during the rest of the inspection period.

A detailed chronology of plant events occurring during the inspection period is included in Attachment I. A summary list of acronyms is contained in Attachment II.

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

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

2.1 Control Room Emergency Ventilation Actuation

On August 17 and again on August 20, 1990, the control room emergency ventilation system actuated. A spurious spike on the 'B' control room radiation monitor caused both actuations. Licensed operators reset the actuations and restored normal ventilation.

Spiking by the 'B' control room radiation monitor is a recurring problem. During the month of July the system actuated four times (see inspection report 50-277/90-14, 278/90-14). In response, the licensee procured a replacement monitor. However, upgrade modifications made

to the monitor by the manufacturer caused it to be incompatible with the licensee's system. During attempts to replace the monitor several dirty connectors were found and cleaned. Also, a faulty ribbon connector cord was found and replaced. No other control room emergency ventilation actuations have occurred since these repairs. The Maintenance/I&C organization submitted a modification request to replace the outdated radiation monitors.

2.2 Unit 2 High Pressure Coolant Injection System Inoperable

On August 21, 1990, the licensee declared the high pressure coolant injection (HPCI) system inoperable as a result of ongoing surveillance testing. In preparation for calibration of the 2D and 2B 125 VDC battery charger undervoltage alarm relays, the Shift Supervisor (SSV) reviewed Technical Specification (TS) 3.9.A and Plant Operations Review Committee (PORC) Position Paper 35. PORC Position Paper 35 establishes the licensee's interpretation of the operability impact of removing a battery or charger from service. Because the calibration procedure reduces voltage below the minimum 123.5 VDC required, the SSV declared the 2D and 2B batteries inoperable. Since the 125 VDC system voltage also affects the 250 VDC system, he also declared the associated 250 VDC system inoperable. The TS Limiting Condition for Operation (LCO) for an inoperable battery was entered. The adjustment was completed on the 2D charger successfully. While making the 2B charger adjustment, the battery voltage could not be lowered using the float adjustment far enough to determine the as-found trip value. The technicians turned off the charger, as allowed by the procedure, to further lower the voltage. When the as-found set point was determined the charger was turned back on and the charger AC feeder breaker tripped. It was reset immediately by an operator.

PORC Position Paper 35 states that the reviewer should consider the loads fed by the battery inoperable when the battery is inoperable. It directs the reviewer to evaluate the associated system TS. The SSV overlooked the systems that should have been declared inoperable in accordance with the PORC Position. He discovered the error when the 2B charger feeder breaker tripped. In addition, the SSV was unaware that the procedure allowed the technicians to turn the charger off during the calibration.

A review of the 2B and 2D battery loads indicated that the following systems should have been inoperable when the batteries were declared inoperable; HPCI, alternate rod insertion system (ARI), core spray (CS) 'B', residual heat removal (RHR) 'B', loss of coolant accident (LOCA) start of the E-2 and E-4 emergency diesel generators (EDG), all loads on the E-22 and E-23 4 KV buses, the motor driven fire pump and emergency service water (ESW) pump 'B'. A decision was made to make a late 4 hour ENS call reporting the HPCI system inoperability. Only the HPCI inoperability was reported because the operator believed that this was the limiting LCO. However, the inspector noted that the inoperability of the above systems places the plant in TS 3.0.C, since the condition is not covered by any specific LCO. Although the licensee may have entered 3.0.C, the LCO time limits were not exceeded and were only applicable for a brief period of time.

The SSV apparently did not have a complete understanding of the calibration procedure, and PORC Position Paper 35. Several events occurred in the recent past involving implementation of this PORC position, and should have led to operational sensitivity. However, the PORC Position does not provide the reviewer with a list of associated battery loads. To determine loads a reviewer must review electrical single line drawings. To perform the calibration the I&C technicians used procedure M-057-004, "125 Volt Class 1E Battery Charger Maintenance." The procedure precautions state an incorrect voltage operability limit of 116 VDC. In addition, the procedure prerequisites do not limit the plant conditions under which the procedure can be performed, thus creating a situation in which the licensee voluntarily enters TS 3.0.C. TS 3.0.C exists to provide direction for a prompt plant shutdown in the event that the plant condition is beyond that considered in the TS. Voluntary entry into 3.0.C is discouraged and should be avoided for all foreseeable cases since it involves multiple reductions in redundancy or safety margins provided in plant design.

The licensee event report (LER) submitted by the licensee addressing this event does not include discussion of the 3.0 C entry nor does it describe corrective action directed at the procedural deficiencies. This issue was discussed with plant management. This item will remain unresolved pending evaluation of the licensee's review of the concerns raised by the inspector (UNR 90-17-01).

2.3 Unit 2 Inoperable Reactor Water Level Instruments

On August 30, 1990, at 6:12 p.m., the licensee initiated a Unit 2 shutdown when all the reactor water level instruments on the 2 'B' reference leg condensing chamber were declared inoperable. TS 3.0.C required the plant to be in hot shutdown in 6 hours and cold shutdown in 36 hours. The mode switch was taken to shutdown at 9:51 p.m. from 30% power. A group II and III engineered safety feature (ESF) actuation occurred when reactor water level reached 0 inches as a result of the scram. The isolations were reset and Unit 2 reached cold shutdown on August 31. See Section 3.0 for further discussion of this event.

2.4 Unit 2 Shutdown Due to an Electro-Hydraulic Control System Fluid Leak

During a Unit 2 reactor startup on September 6, 1990, an electro-hydraulic control (EHC) system fluid leak was discovered on the #4 main turbine bypass valve. The control room staff responded quickly to a low EHC fluid reservoir level alarm, diagnosed the problem and initiated action. The leak was minimized by opening the #4 bypass valve. Operators reduced reactor power from 26% to 5%. The RCIC system had been removed from service for performance of maintenance tasks. Because the licensee anticipated the need to trip the EHC system immediately following the scram, the reactor was maintained at low power until RCIC was returned to service. This decision was made to ensure an easily controllable decay heat removal path after isolation of the condenser. The licensee later manually scrammed the reactor and performed a controlled cool down without incident.

Maintenance personnel found four loose servo-actuator mounting bolts on bypass valve HO-4282A. The as-found torque values were 0, 110, 40 and 70 ft-lbs. The licensee believes that the bolts should be torqued to about 170 ft-lbs. Maintenance personnel removed the servo, replaced the O-rings and torqued the bolts to 170 ft-lbs. The licensee examined the other 8 bypass valves to determine bolt tightness. Since only 2 of the 4 bolts on each bypass valve were accessible, they were checked first. Torque valves ranged from 0 ft-lbs to 170 ft-lbs. Based on the scatter, the bypass valves were partially disassembled to check the remaining bolt torques. These values ranged from 70 ft-lbs to 165 ft-lbs. All the bolts were torqued to 170 ft-lbs and the bypass valves were reassembled.

Two previous EHC fluid leaks occurred on Unit 3 on January 28 and June 25, 1990. Both involved leaks on the turbine control valves. In response to the January 28 event, maintenance engineering initiated a failure analysis report (FAR). Although the FAR did not determine an exact root cause, inadequate servo-actuator mounting bolt torque was noted as a probable cause. When the second event occurred, only the Unit 2 and 3 control valve servo-actuator mounting bolts were checked. Unit 3 bolts were adequately torqued, but the Unit 2 bolts were randomly under-torqued.

The inspector concluded that the licensee had an opportunity to also check other similar servo-actuator bolt torque valves after the June 25, 1990 event. At that time neither Units' bypass valves or #2 stop valves were checked. After the third event, all the Unit 2 bypass valves were checked, but the #2 stop valve was overlooked. The licensee has not had a good opportunity to check similar bolt torques on Unit 3. It is possible that these bypass valve bolt torques are random. The licensee will check these bolts during the upcoming Unit 3 mid- cycle outage.

2.5 Unit 2 Reactor Water Cleanup Isolation (RWCU)

While performing a routine Unit 2 functional surveillance test (ST) of differential pressure switch DPIS 2-124A on September 9, a Group IIA primary containment isolation system (PCIS) actuation occurred. This closed the inboard RWCU motor operated isolation valve, MO-2-12-15. The isolation was reset and the system returned to service within 20 minutes.

Two I&C technicians were performing test procedure SI2F-12-124-A1FM. This test requires that a jumper be installed in the cable spreading room by one technician, while the second technician performed valving and calibration activities in the reactor building. The technicians did not discuss the activity in detail prior to the job so there was not a clear understanding of the responsibilities. The procedure did not require double verification, as is usually required for jumper installation. The result was that each technician thought the other had installed the jumper. The procedural step to assure that the jumper was installed was missed during radio communication. The result was the isolation of RWCU when the technician in the field raised the pressure at DPIS 2-124A.

The procedure was temporarily changed to add a double verification step, and the technicians repeated the procedure successfully. The licensee stated that the procedure will be permanently

modified to include the double verification step, and similar procedures will be reviewed to assure that steps requiring installation of jumpers will have a double verification step. At an "All Hands" meeting I&C personnel were instructed in proper pre-job review techniques. The confusion in radio communication will be resolved by practice in proper radio communication after review of the already established Operations Department radio practices. The inspector had no further questions.

2.6 High Pressure Service Water Pump Bay Flood Protection

On September 10, 1990, the licensee informed the NRC that in the event of a design basis flood, a 4 inch penetration would have provided a flow path into the Unit 2 high pressure service water (HPSW) pump bay. The HPSW pump bay contains all four Unit 2 HPSW pumps and one of two emergency service water (ESW) pumps. Flooding of the HPSW pump bay could result in common mode failure of the HPSW and ESW pumps. The licensee discovered this problem after concerns with temporary flood seals were identified at Limerick.

The licensee permanently sealed the 4 inch penetration by removing the temporary seal and filling the penetration with 8 inches of grout. The inspector found no discrepancies with the penetration seal work release or the grout placement checklist. See Section 4.2 for further details.

2.7 Unit 3 High Pressure Coolant Injection System Inoperable

On September 10, 1990, while performing ST 6.5.1, "HPCI Auxiliary Oil Pump Surveillance," the Unit 3 high pressure coolant injection (HPCI) system auxiliary oil (AO) pump failed to start. The licensee declared the HPCI system inoperable. The operating shift determined that the time delay relay (Cutler Hammer model 673) in the starting circuit that cuts out the starting resistors did not operate properly. The relay contacts had oxidized affecting operation. The relay's freedom of motion was checked with no evidence of binding. Following these observations, operators retested the HPCI AO pump. It was successfully started 5 consecutive times. Based on this testing, the licensee determined that HPCI was available, but it was not declared operable until engineering and maintenance evaluated the relay.

Maintenance request form (MRF) 9006441 was written to clean and inspect the relays in the starting circuit of the HPCI AO pump. The inspector observed the activity. The licensee took appropriate steps to de-energize the circuit before performing maintenance. The relay contacts were cleaned, freedom of motion was verified and contact continuity was checked. The inspector did not observe any deficiencies during the maintenance activity. Operators reperformed ST 6.5.1 satisfactorily and the Unit 3 HPCI system was declared operable on September 11, 1990.

The inspector determined that the licensee's preventive maintenance (PM) program did not include the starting circuit relays associated with the HPCI or RCIC systems. The licensee indicated this could be attributed to having the HPCI and RCIC system motor controls located in the pump rooms, rather than in a motor control center (MCC). The PM program was

developed and implemented on a MCC basis. The fact that some HPCI and RCIC electrical components were not in the PM program was previously documented in combined inspection report 50-277/90-01, 50-278/90-01 dated March 27, 1990. As a result of the recent failure, the HPCI system engineer reviewed the MRF history and identified seven similar failures. Based on this review the system engineer requested maintenance to perform a failure analysis to determine the corrective actions needed to prevent recurrence. The HPCI system engineer stated that the HPCI and RCIC system motor control relays will be added to the PM program.

2.8 Unit 2 HPCI Inoperable Due to Low ESW Flow

On September 13, 1990, during performance of ST 21.5-2, "ESW Flow Test Through ECCS Room Coolers and RHR Pump Seal Cooler - Unit 2," the high pressure coolant injection (HPCI) system was declared inoperable. Unit 2 was at 82% power. System engineers measured low emergency service water flow (ESW) through the available room cooler. The redundant room cooler was valved out of service due to previous ESW flow problems. In accordance with TS 3.5.H, if both HPCI room coolers are inoperable, the HPCI system must be declared inoperable. The licensee entered a 7 day TS LCO and began testing the other required ECCS.

System engineers used ultrasonic flow measuring equipment to detect the low ESW flow condition. In order to verify the problem, they began preparations for a "bucket test." This test accurately measures the amount of ESW flowing through the coolers into a calibrated drum in a measured time. The unit cooler outlet valve is disassembled to provide the flow path to the drum. At this point, corrosion and silt was flushed into the drum. The unit cooler subsequently passed adequate flow and the HPCI system was declared operable 12 hours after initiation of the TS LCO. The inspector had no further questions.

2.9 Potential Loss of Intake Structure Ventilation

On September 13, 1990, the licensee discovered that ventilation for safety-related pumps in the intake structure would fail to operate during a design basis accident. The HPSW and ESW pumps for both units would be affected. The licensee found the problem as a result of a licensee conducted safety system functional inspection (SSFI) and subsequent follow-up by nuclear engineering personnel.

There are two fans per unit. Four pressure switches (PS-20224-1 and 2 for Unit 2 and PS-30224-1 and 2 for Unit 3) that start the ventilation fans can not perform their function if instrument air is lost. The control switches for the fans have 4 positions; off, auto, auto-standby, and run. For each unit one switch is set in the auto and one in the auto-standby position. When temperatures exceed 70 degrees F in the room, a temperature indicating controller allows instrument air to act on the pressure switch. Actuation of the pressure switch starts the fan selected to auto. If the lead fan fails to start (due to any reason but a loss of instrument air), the fan in auto-standby will start. If instrument air is lost the temperature controller would not act to start the fans, potentially causing failure of the HPSW and ESW motors due to overheating.

To correct the problem, the licensee immediately placed one fan for each unit in the run position so that a loss of instrument air would not stop the energized fan. The licensee is pursuing a modification to the control system so that when a loss of instrument air occurs, the fan will start. The licensee stated that no other vital equipment in the plant would fail to perform its intended function on a loss of instrument air. The inspector questioned licensee personnel concerning the adequacy of their response to Generic Letter 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," and why this problem was not identified during that review. This area will remain unresolved pending further licensee investigation (UNR 90-17-02).

2.10 Standby Gas Treatment System Inoperable

As part of a review of temporary flood seals the licensee found a 2 inch conduit open to the HPCI atmosphere at the 105 foot 3 inch elevation. A temporary, unqualified seal was in place inside the conduit at the point where it penetrates the HPCI room wall. After passing through the wall the conduit connects to the junction box that powers the heaters for the "B" train of the standby gas treatment system (SGTS). Also, the licensee identified an empty conduit installed between the terminal boxes for the heaters in the "A" and "B" trains of the SGTS. The penetration, and all of the conduit and junction boxes were located below the 111 foot internal flood level. Based on the potential common mode failure of both trains of SGTS due to a flood in the HPCI room, the licensee declared both trains of the SGTS inoperable on September 14, 1990. TS 3.7.E required both units to be in hot shutdown within 12 hours and cold shutdown within the following 24 hours.

The licensee quickly restored the "A" train of the SGTS to an operable status by removing a portion of the empty conduit and capping the remaining conduit. With the "A" train of the SGTS returned to an operable status, the licensee entered TS LCO 3.7.B that allowed 7 days to restore the other train to an operable status. To repair the "B" train, the licensee removed the temporary penetration seal and installed a permanent flood seal. When the seal was fully cured after 24 hours, the licensee declared the "B" train of the SGTS operable and exited the TS LCO.

Nonconformance report (NCR) P-90582 was issued documenting the condition and the corrective actions taken. The inspector reviewed the NCR and inspected work performed to seal the penetrations. No additional concerns were identified. This issue is discussed further in Section 4.2 of this report.

2.11 Lightning Strike Causing ESF Actuations

On September 16, 1990, at 8:05 p.m. a lightning strike caused a transient in the No. 3 start-up 220 KV line and a trip of breaker 3435, and loss of the 13.2 KV feed to the plant. This partial loss of offsite power caused emergency buses to fast transfer to their alternate source. During the transfer, the Unit 2 B reactor protection system (RPS) motor generator (MG) set tripped, causing a half scram. This also caused half actuation of B PCIS Group II and III reactor building ventilation system isolation. The B RPS MG set was restarted and the isolation was reset, ventilation was restored to normal. Unit 3 responded to the strike with a similar fast

transfer and a half actuation of PCIS Group II and III, which was reset and restored. The licensee investigated the trip of the Unit 2 B RPS MG set and found that a time delay relay used to seal in the motor start circuit had a timing misadjustment. It should have been adjusted at 7 seconds but was found set at O seconds. This condition did not allow the seal feature to work. Proper operation of the relay would have sealed in the start for 7 seconds, allowing a brief interruption of power during the fast transfer. The out of calibration component is not safety-related, and resulted in the MG set output failing in the conservative direction. The licensee is investigating the cause of the misadjustment and if other relays have a similar problem, but no conclusion had been reached before the end of the inspection period.

3.0 REACTOR WATER LEVEL TRANSMITTERS OUT OF CALIBRATION

During the report period the licensee discovered that one of the Unit 2 reactor water level monitoring reference legs had a reduced level, affecting multiple instruments. Later the licensee discovered that two Unit 3 reactor level transmitters had been miscalibrated during the last outage. These incidents are discussed in detail below.

3.1 Unit 2 Level Transmitters

On August 23, 1990, the Unit 2 day shift reactor operator recorded plant parameters using shiftly ST 9.1-2X, "The Surveillance Log, (Hot Shutdown, Startup/Hot Standby or Run Mode)." This procedure, along with other similar procedures, implements the TS required instrument daily channel checks. The procedure requires verifying that instrument readings are within a certain band. This band is typically wide, and for most level instruments is either 0 to +20, +5 to +30 or +5 to +35 inches. While the procedure directs the performer to compare like instrument channel readings, it does not provide guidance on the acceptable deviation between channels. The operator flagged the value indicated by level recorder (LR) 2-2-3-110B (green pen) as abnormal because it was reading 2" greater than its limit of +30 inches.

Following a power decrease on the same day, the afternoon shift operator flagged the values of LI 2-2-3-85B and LR 2-2-3-110B (green and blue pens) as abnormal because they indicated greater than their high limits. The signals feeding these indicators originate at the 72B and D level transmitters. The afternoon shift attributed the high readings to the power decrease. Because of the location of the wide range reactor level instrument reference leg tap, the associated indication is affected by recirculation flow. The tap is located near the narrowest point of the annulus. High flows create a venturi effect. Reduced recirculation flow results in a higher pressure at the tap and a corresponding increase in indicated level. The narrow range instruments, including the feedwater control level signal, do not exhibit this response because of the different location of the variable leg tap. This change is not gradual but occurs almost as a 10 inch step increase when reactor power is decreased through 90%. However, no one investigated the high reading taken on day shift before the power decrease. They did not recognize that all instrument indication coming from the 2B reference leg, including the instruments discussed above, had been slowly trending higher since early August.

Over the next 6 days indicated water level values associated with instruments served by the 2B condensing chamber and reference leg continued to drift upward, diverging from level instruments on the other reference leg. On August 29, operators requested that the shift technical advisor (STA) investigate the problem. The STA determined that there was a definite level offset between instruments on the 2B reference leg and other water level indications. The STA requested that I&C investigate the problem.

I&C engineering, nuclear engineering, site management, and General Electric (GE) began an investigation of the problem. I&C checked for excess flow check valve leakage, instrument line leakage, equalizing valve position, abnormal drywell temperatures, recirculation flow effects, loss of transmitter sensor oil and verified the accuracy of control room indications. GE reported that another licensee had a similar problem caused by a buildup of non-condensible gases in a condensing chamber.

The licensee evaluated the impact of the level offset and concluded that the associated instruments on the 2B reference leg would function, but would not generate their trips at the TS required setpoints. The licensee declared the instruments inoperable and entered TS 3.0.C, requiring the plant to be in hot shutdown in 6 hours. The instruments that were declared inoperable provide: 1) double low level initiation of HPCI, RCIC, alternate rod insertion (ARI), and reactor recirculation pump trip (RPT); and 2) triple low level initiation of MSIV closure, core spray (CS), low pressure coolant injection (LPCI) and EDG. Below is a table of affected instrument numbers, calculated and TS required settings, and functions.

INST #	TS SETPOINT	CALC SETTING	FUNCTION
72B	-48	-52.56	HPCI, RCIC, and ARI initiation; RPT
	-160	-164.62	LPCI, CS and EDG initiation; ADS input
72D	-48	-54.47	Same as above
	-160	-166.53	Same as above
99C	-160	-168.94	MSIV PCIS Group I isolation
99D	-160	-168.94	Same as above

Following the shutdown, the licensee confirmed that water level in the 2B reference leg was low and began looking for leaks. The licensee backfilled the reference leg and pressure tested level transmitters and equalizing valves on the 2B reference leg. No leaks were found. However, since the licensee hand tightened the equalizing valves during troubleshooting before the

shutdown, a small leak might have been stopped. They also performed dye penetrant testing of all welds in the drywell and found no leaks. During the recent outage the licensee implemented a modification which replaced the original level instrument equipment with the current condensing chamber design. The licensee theorized that due to poor condensing chamber placement, non-condensible gases built up in the condensing chamber and reduced the condensing rate over time. A small leak, possibly through an equalizing valve, allowed the leg to decrease.

After identification of the problem on August 29, the licensee took prompt and proper action. Licensee management was involved, directed staff evaluations and supported appropriate operability decisions. However, daily channel checks since about August 6 indicate that water level instrumentation on the 2B reference leg was drifting upward. Since the acceptance band for various water level instruments was wide (25 inches), drifting went unnoticed for some time. On August 24, daily channel checks noted a deviation of 10 to 12 inches between like channels. The affected instruments probably exceeded their TS setpoint about that time. The logic using the 72B & D, and 99C & D instruments is one-out-of-two twice. The 72B and 99C are in trip system I. The other two are in trip system II. One channel in each of the trip systems located on the redundant condensing chamber was operable during the time frame and would have actuated at the proper water level. However, redundancy was lost. The channels exhibiting the offset were functional and would have initiated, but at a lower than TS allowed water level.

3.2 Unit 3 Level Transmitters

During the extended shutdown from 1987 to 1989, a reactor vessel level instrumentation modification was implemented. Part of the modification acceptance test consisted of calibrating level transmitters (LT) 3-2-3-99C and D. Unit 3 started up in October 1989. As early as December 8, 1989, the 99C and D instruments were flagged as being high on ST 9.1-3X and out of the normal tolerance band (5 to 35 inches). They were indicating about 10 to 15 inches higher than their 99A and B redundant channels. No action was taken until December 27 when two MRFs (8911311, 8911312) were written. However, the MRFs were canceled on January 17 because the indicated water levels had dropped to within the tolerance band when reactor power exceeded about 90% on January 6.

Over the next several months, reactor water level on the 99C and D indicated about 10 to 15 inches higher than 99A and B. However, they were generally within the tolerance band. During those months several readings were out of the tolerance band, but were attributed to load drops.

On March 17, a Unit 3 operator flagged an out of tolerance water level indication on LT 99D. MRF 9002008 was written to investigate the problem. The MRF was canceled on March 30 because the indicator had returned to and remained within the tolerance band for the intervening two weeks.

During the first two weeks of May, LT 99D was indicating high outside the tolerance band. MRF 9003454 was written to address the problem. However, the MRF was put into the mid-cycle work list because I&C believed the problem was attributable to the indicators only.

In August, operations personnel requested that I&C engineers investigate the level offset again. Transmitter output voltage readings were taken and agreed with the indicator reading. It was noted that the LT 99C and D indicator scales were -165 to +50 inches. The design specification called for a range of -165 to +60 inches. I&C recalculated reactor water level values based on the smaller scale. The scale error affected only the local trip unit indicator and not the trip settings or the control room indication. The rescaled LT 99C and D indications were closer to the level indication derived from the feed water control system than the redundant 99A and B transmitters. Based on this I&C engineers concluded that the 99C and D transmitters were reading normally, and the 99A and B transmitters were reading conservatively low. This evaluation is documented in an internal I&C memo dated August 8, 1990. On August 15, the indicator for LT 99D was recalibrated under MRF 9003454.

Following the Unit 2 water level problem in late August, and recognition of the effect of recirculation flow on the wide range instruments, the Unit 3 problem was revisited. It was concluded that LT 99C and D were indicating non-conservatively high. A setpoint change was implemented on September 11 for LT 99C and D to raise the trip setpoint from -157 to -130 inches to compensate for the offset. That same day, LT 99D calibration was checked, it was found out of calibration by about 10 inches and it was recalibrated. The licensee decided not to check LT 99C due to the risk involved in working on these transmitters at power. The original setpoint for LT 99D was restored but the setpoint for LT 99C remains at -130 inches.

The 99C and D instruments initiate the triple low water level MSIV closure signal. Below is a table of the affected instruments, their as-found and TS required settings, and their function.

INST #	TS SETPOINT	AS-FOUND SETPOINT	FUNCTION
99C	-160	-168	MSIV PCIS Group I isolation
99D	-160	-167	Same as above

Daily channel checks since the Unit 3 startup in November 1989 indicated that LT 99C and D were tracking water level non-conservatively high. The LTs were both calibrated on the same day (July 25, 1989) and by the same personnel. Review of the surveillance test implies adequate performance. The licensee is investigating the cause of the miscalibration.

The logic using the 99C and D instrument output is one-out-of-two-twice. LT 99C is in trip system I and LT 99 D is in trip system II. One channel in each of the trip systems was properly set during the time frame. The MSIV closure would have occurred at the proper water level. However, redundancy was lost. The out of calibration channels would have initiated a closure, but at a lower than TS allowed water level.

3.3 Conclusions

In both instances, once the licensee identified the problem, they took quick corrective action. The licensee shut down Unit 2 and raised the trip setpoints for Unit 3. The Unit 2 problem was a result of a previously unrecognized design weakness and could not reasonably have been foreseen. The Unit 3 problem was created due to improper calibration. However, of concern in both cases is the duration of the problems, the missed opportunities to detect them and the number of inoperable instruments.

TS Table 3.2.A, "Instrumentation That Initiates Primary Containment Isolation," Item 3, requires two operable instrument channels per trip system with setpoints at or above -160 inches indicated level. TS Table 3.2.B, "Instrumentation That Initiates or Controls the Core and Containment Cooling Systems," requires two operable instrument channels per trip system with trip level settings equal to or greater than -48 and -160 inches indicated level (depending on function). Between about August 24, 1990, and the time of the Unit 2 shutdown on August 29, 1990, only one PCIS channel on each trip system was set equal to or above -160 inch indicated level. Also, only one ECCS initiation channel on each trip system was set equal to or above the above -48 or -160 inch indicated water level.

Between the Unit 3 startup in October 1989, and the time that each ECCS trip level setpoint was raised on September 11, 1990, only one channel on each MSIV Group I PCIS trip system was set equal to or above -160 inches indicated level.

Since the actions required by TS Tables 3.2.A and 3.2.B were not applicable, TS 3.0.C applied. Both Unit 2 and Unit 3 were required to be in hot shutdown within 6 hours and in cold shutdown within 36 hours unless corrective measures were completed to satisfy the TS. Unit 2 violated TS 3.0.C for approximately 6 days and Unit 3 violated TS 3.0.C for approximately 11 months (NV 90-17-03). No Notice of Violation is being issued for this violation at the present time. Enforcement action is pending conduct of an enforcement conference.

TS define an instrument or channel check as a qualitative determination of acceptable operability by observation of instrument or channel behavior during operation. This determination shall include, where possible, comparison of the instrument or channel with other independent instruments measuring the same variable. This is the intent of ST 9.1-2X, Y and Z and ST 9.1-3X, Y and Z. The inspector concluded that if the licensee had performed effective channel checks, both problems may have been discovered sooner. The tolerance bands selected for the instruments were too wide and did not enable operators to perform adequate checks. In addition, the as-left setpoints required by calibration procedures appear to set some of the instruments close to the TS setpoints, making this type of calibration error or drift difficult to detect prior to exceeding the required setpoints. Investigations initiated by operations because of instrument performance concerns were not effectively analyzed and dispositioned. Finally, at the close of the inspection, the licensee had not yet determined the cause of miscalibrating LT 99C and D on Unit 3.

At the enforcement conference, the licensee should be prepared to discuss the following specific issues along with their general presentation:

-- Safety significance of problem on each unit;

-- Adequacy of channel check program and appropriateness of tolerance band for various channel checks;

-- Adequacy of the evaluation of the Unit 3 problem performed in response to concerns raised by operations;

-- The root cause for the Unit 2 reference leg decrease, and

-- The root cause for the Unit 3 miscalibration.

A thorough understanding of these issues is important to proper characterization of the significance of these problems.

4.0 ENGINEERING AND TECHNICAL SUPPORT ACTIVITIES (37700)

4.1 Unit 3 Safety Relief Valve Bellows Leak Detection

The main steam safety relief valves (SRV) have non-safety related bellows leak detection pressure switches. They detect leaking pilot valve bellows during plant operation and activate a control room annunciator.

On July 16, 1990, system engineers found a battery ground on the drywell cable to the bellows pressure switch for the Unit 3 SRV 71F. The licensee believes that the ground is located in the connector plug; therefore the pressure switch is functional. The licensee contends that past experience with this type of connector plug supports their position.

TS 4.6.D.3 requires continuous monitoring of SRV bellows integrity. To fulfill this requirement, and remove the ground from the DC circuit, the licensee prepared temporary plant alteration (TPA) #01-20. The TPA removed the pressure switch from the DC circuit and connected it to an AC current monitoring device. This device consists of a power indicating light, and a light and horn that would actuate if the bellows ruptured. Non-licensed operators monitor this device as part of their shift rounds at least three times a day. The TPA will remain in effect until the mid-cycle outage scheduled for late October 1990.

The inspector reviewed administrative procedure A-42, "Procedure for Control of Temporary Plant Alterations (TPAs)," Nuclear Group Administrative Procedure NA-02R002, "10 CFR 50.59 Reviews," associated electrical prints, PORC meeting minutes and the installed monitoring device. The inspector agreed that the methodology used in the licensee's TPA would serve to

monitor bellows leakage provided the bellows pressure switch is intact. The licensee will repair the ground during the mid-cycle outage.

4.2 Temporary Penetration Flood Seals

As a result of concerns identified at Limerick, the licensee reviewed the use of temporary flood seals at Peach Bottom. Inspection Procedure (IP) 5.8, "Procedure for Installation and Inspection of Penetration Seals and Encapsulation," referenced details 44 and 45 of drawing M-3010 "Penetration Seals," as temporary seals to install in penetrations while open during modification. However, details 44 and 45 were described as temporary fire seals and had not been reviewed to determine if they provided adequate flood protection.

The licensee reviewed modifications that involved the creation of new penetrations or opened existing penetrations. This review identified two penetrations below the 135 foot external flood protection level and three penetrations below the 111 foot internal flood protection level as potential problems. The penetrations are listed below:

Penetration	Location	Description	Elevation	Date
48-3006E	Unit 3 HPCI Room	2" conduit	105' 3"	4/6/90
*144-3008	Unit 2 HPSW Pump Bay	4" core bore	125' 11"	5/24/90
*144-3008B	Unit 2 HPSW Pump Bay	1" conduit	125' 11"	5/24/90
3-1518	Unit 2 "C" RHR Pump Room	9" core bore	110' 9"	6/23/90
3-1519	Unit 2 "C" RHR Pump Room	9" core bore	110' 9"	6/23/90

*external flood barriers

Discovery of the inadequate seal in penetrations 144-3008 and 48-3006E initiated the ENS notifications described in Section 2.6 and 2.10 respectively. To prevent creating additional penetrations susceptible to flooding, the licensee suspended all maintenance and installation work that could open penetrations. Licensee evaluation of penetrations 3-1518 and 3-1519 determined that the controlling procedure (modification package 5046) had already provided an engineering approved temporary penetration flood seal. The licensee permanently sealed penetration 144-3008 by removing the temporary seal and installing 8 inches of grout. Penetrations 144-3008B and 48-3006E were closed with a permanent flood seal as documented in NCR P-90574. These permanent flood seals consisted of about 9 inches of Dow Corning 3-6548 Silicone Foam (SF-

20). The inspector reviewed associated drawings, NCRs, engineering work request (EWR) P-8014, penetration seal work releases, and grout placement checklists. The installed permanent seals and grout repairs were also reviewed. The licensee is evaluating existing penetration seal qualifications, developing an alternate qualified seal design, and reviewing program controls applicable to temporary seals. These efforts will be completed prior to restarting activities which could open penetrations.

Prompt communication of this issue within the licensee organization after it was raised at Limerick resulted in performance of the review and correction of the problem. However, the inspector noted that the licensee had previously questioned the acceptance of details 44 and 45 of drawing M-3010 as temporary flood seals. This was documented in EWR P-51713 dated May 24, 1990. Site personnel requested that engineering accept these details as flood seals or provide an alternate flood seal detail. At the time, the question was not raised regarding the current practice of using these details in flood barriers. The engineering evaluation for the EWR had an agreed upon completion date of September 21, 1990. During discussions with the installation group and engineering the inspector questioned the timeliness of the review and the failure to identify the ongoing use of these temporary fire seals in flood barriers as a potential immediate problem. A thorough review of the concern at the time the EWR was written should have identified the existence of the flood barrier penetration inadequacies. Nuclear engineering stated that an alternate flood seal detail will be provided.

4.3 High Energy Line Break Protection

The licensee initiated a review of high energy line break (HELB) controls in place at Peach Bottom based on concerns identified with inadvertent blocking of HELB vent paths at Limerick. The outcome of the review revealed that the existing program to control penetrations, as outlined in IP 5.8, did not address controls for HELB barriers. None of the permanent or temporary penetration seals installed during modifications were analyzed to withstand the pressures encountered during a HELB event. Also, controls for HELB vent paths were inadequate to ensure that these paths remained open.

Penetration seal failure during a HELB event could subject equipment in an adjoining room to an environment that exceeds its environmental qualification rating. The potential for a seal failure increases as room pressure increases. Increased room pressure would result from blocking HELB vent paths. Walkdowns of the HELB vent paths were immediately started with no problems identified before the close of the inspection period. An engineering evaluation of installed penetration seals was started to determine if they can withstand the 2 to 10 psid developed during a HELB event. The engineering evaluation is currently underway. This item will remain unresolved pending completion of the evaluation and walkdowns (UNR 90-17-04).

4.4 Main Steam Isolation Valve Packing Repair

During the inspection period Unit 2 outboard MSIV 86B developed a significant packing leak. The licensee elected to perform a temporary leak repair by injecting sealing material into the

packing through the packing leak-off line. The licensee developed a safety evaluation assessing the effect of the sealant on MSIV reliability, and its compatibility with valve and other reactor coolant system materials. The licensee measured the valve stroke length and time before and after injection of the sealant. No change was observed. The inspector reviewed the evaluation and discussed it with NRC Region I specialists. Since the packing is not considered part of the ASME Section XI pressure retaining boundary, the work was planned and approved as a non-Code repair.

During the attempt to inject sealant the licensee found that this method was not viable. Following discussions between the station maintenance engineers and the nuclear engineering department the licensee decided to drill a pilot hole in the valve bonnet, into the packing cavity. A small valve was threaded into the pilot hole and the sealant injected. This evolution stopped the leak. Drilling a hole in the valve bonnet has the potential to affect the component pressure retaining capability and therefore should have been considered a Code repair. Code repairs to Class I piping require a preapproved repair plan. In this case no repair plan had been prepared because the licensee incorrectly classified the activity. Following completion of the work the licensee recognized the error. An evaluation of the effect of the pilot hole and installation of the valve was performed. This included review of the repair by the valve manufacturer. The licensee concluded that the repair did not represent any degradation. The licensee prepared and approved a repair plan, the authorized nuclear insurer representative concurred, and the plan was used to document the previously completed work. The licensee was able to perform all inspections and measurements required by the plan.

In response to this and several other recent incidents in which maintenance activities were not properly controlled, the licensee's quality assurance organization issued a Corrective Action Request. This will ensure licensee action to resolve the underlying performance weakness. Licensee response was appropriate and the inspector had no further questions.

The inspector noted during discussion of the MSIV packing repair that the packing, gland and follower for this valve are classified as nonsafety-related. The licensee stated that all packing and gasket materials had been designated as nonsafety-related. Packing is not considered a pressure retaining component. For applications where packing and gasket leakage are not significant and do not impair the system's ability to perform its function this would be appropriate. However, in this and possibly other instances the packing forms part of the primary containment boundary. Packing leakage in this application can adversely affect containment integrity. The inspector requested to review the licensee's evaluation supporting classification of these materials as nonsafety-related. The evaluation was not available before the close of the inspection period. This item remains unresolved pending review of the licensee's evaluation (UNR 90-17-05).

5.0 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 checks, jet pump operability, and control rod operability were verified to be adequately performed.

In early September 1990, non-licensed operators performed monthly ST 8.1.16. They noted an excessive amount of water in the E-4 EDG fuel oil sample. As directed by ST 8.1.16, maintenance personnel pumped-out about 100 gallons of water from the bottom of the tank. The inspector reviewed related fuel oil TS, surveillance tests, Regulatory Guides and standards. The inspector determined that the licensee meets appropriate diesel fuel oil monitoring, sampling and analytical requirements. The inspector had no further questions.

A list of surveillance tests reviewed or observed is included as Attachment III. No concerns, except as previously described in Section 2.7 of this report were identified.

6.0 MAINTENANCE ACTIVITY OBSERVATIONS (62703, 71707)

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

On July 26, 1990, the maintenance group completed the annual inspection on the E-2 EDG. They turned it over to the system engineer who performed ST 8.1.6, "Diesel Generator Annual Inspection Post-Maintenance Test." The system engineer stated that while performing the ST he checked all fluid levels, slow started the EDG, and exercised the Woodward governor to remove entrapped air. ST 8.1.6 was completed on July 29. Operators successfully fast-started the EDG using ST 8.1, "Diesel Generator Full Load Test." The licensee returned the EDG to service.

On August 7, operators started the E-2 EDG in accordance with ST 8.1. It started in 12 seconds, rather than the maximum allowable time of 10 seconds. The E-2 EDG was shut down and retested. This time it started in 7 seconds. The EDG was declared inoperable pending resolution of the slow start. Later in the day the system engineer re-performed a portion of ST 8.1.6 to exercise the Woodward governor to ensure all air bubbles were removed. Operators restarted the E-2 EDG successfully in less than 10 seconds and it was declared operable.

The EDG was successfully tested two more times. However, plant operators noticed that the lube oil head tank level was low. The engine sump, oil heater and filter have a capacity of about 800 gallons. The licensee believed that failing to vent the lube oil system after completion of maintenance in late July caused the low level.

The licensee enhanced ST 8.1.6 to better exercise the Woodward governor after the engine reaches normal operating temperature. The inspector determined that maintenance procedure M-052-002, "Diesel Engine Maintenance," did not cover filling and venting the lube oil system. The licensee relied on the knowledge of experienced maintenance personnel and engineers to remember to vent the system. To prevent recurrence, a preventive maintenance MRF will automatically be generated when annual EDG maintenance is done to ensure the lube oil system is vented. The inspector had no further questions.

7.0 RADIOLOGICAL CONTROLS (71707)

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

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

8.0 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.

9.0 REVIEW OF LICENSEE EVENT REPORTS (90712)

The inspector reviewed LERs submitted to the NRC and verified that appropriate corrective action was taken and responsibility was assigned, that continued operation of the facility was conducted in accordance with TS, and did not constitute an unreviewed safety question as defined in 10 CFR 50.59. Report accuracy, compliance with current reporting requirements and applicability to other site systems and components were also reviewed.

LER No. LER Date Event Date	Subject
02-89-28, Rev. 1 06/25/90 11/08/89	Standby Gas Treatment System Relays Not Environmentally Qualified
02-90-10 05/31/90 05/02/90	Control Room Emergency Ventilation System Actuation
02-90-15 08/03/90 07/07/90	Control Room Emergency Ventilation System Actuation
02-90-16 08/17/90 07/18/90	Control Room Emergency Ventilation System Actuation
02-90-18 08/29/90 07/30/90	Control Room Emergency Ventilation System Actuation
02-90-20 09/19/90 08/21/90	HPCI Inoperable Due To Low Battery Voltage

10.0 TMI TASK ACTION PLAN ITEM III.D.3.4, CONTROL ROOM HABITABILITY

TMI Task Action Plan (TAP) Item III.D.3.4 requires adequate protection of control room operators against the effects of an accidental release of toxic and radioactive gases. In addition, operators must be able to operate or shut down the plant under design basis accident (DBA) conditions. The licensee contracted Pacific Northwest Laboratories (PNL) to evaluate the habitability of the control room during a DBA concurrent with a release of radioactive and toxic gases. The PNL study concluded that the control room would be safe and habitable under both normal and accident conditions without modifications. However, a modification was required to remove the chlorine gas supply used in the water treatment plant. The licensee modified the water treatment plant and now uses sodium hypochlorite, a non-volatile substance, to treat the water. The licensee removed all chlorine gas tanks on March 1, 1983.

The PNL study also considered a railroad transportation system located across the Susquehanna River from the plant, and vehicle transportation in the vicinity. Although the railroad may carry

some toxic gases, distance and air diffusion studies indicated that toxic levels would not reach the control room intake. The licensee controls vehicle transportation of toxic gases in the vicinity of the plant.

The control room ventilation system trips when high radiation is detected in the intake duct. Ventilation realigns to the emergency mode and outside air passes though charcoal and high efficiency particulate air filters. This air enters the control room at 3000 cubic feet per minute, which keeps the control room pressurized, to prevent infusion of unfiltered air. When high high radiation is detected in the intake duct, the ventilation system isolates. Cooling of the intake air is not provided in either the mode of operation initiated by the high or high high emergency signals.

Heat generated by electronic equipment in the control room and hot ambient outside air would cause high temperatures in the control room. A heat load study indicated that the high high emergency ventilation mode would cause the control room temperature to rise rapidly to at least 130 degrees Fahrenheit (F). Because this was unacceptable for habitability, a modification was recently implemented to remove the high high isolation.

In the emergency ventilation mode initiated by a high radiation signal, the heat load study indicated that with an ambient outside air temperature of 76 degrees F, the control room temperature would rise to 117 degrees F. Since summer temperatures are normally warmer than 76 degrees F., the temperature in the control room would be much warmer. Off-Normal procedure ON-115, "Loss of Normal Main Control Room Ventilation," requires the operators to shut down both units and shed electronic equipment in the control room if control room temperature exceeds 100 degrees F. Analysis indicates that load shedding with an outside air temperature of 95 degrees F would prevent the control room from exceeding 107 degrees F. In addition, operators have a source of water and isotonic solutions for salt replacement.

Engineering studies are in progress to redesign the ventilation system to provide the emergency ventilation mode with heating and cooling coils. In the interim the removal of the high high radiation isolation in conjunction with the established load shedding procedures is adequate. As an additional precaution, control room personnel have an adequate supply of self-contained breathing apparatus available for use.

The inspector concluded that the licensee completed analyses and initiated modifications to address the protection of control room personnel from toxic and radioactive gases. Appropriate administrative controls are in place pending completion of planned ventilation cooling modifications. This item is closed.

11.0 MANAGEMENT MEETINGS (30703)

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. The inspectors also attended the exit interview for the following inspection during the report period:

Dates	Subject	Report No.	Inspector
8/20-24	Facility Radiation Protection	90-16/16	Chawaga

ATTACHMENT I

Facility and Unit Status

Unit 2

August 14	Reactor power at 100%.
August 22	Power reduced to 50% for control rod pattern adjustment.
August 23	Power increase stopped at 52% when a steam leak was identified on the 'B' outboard MSIV packing.
August 25	Power increased to and held at 75% until engineering evaluated the MSIV leak repair method.
August 28	MSIV opened and power increased to and held at 80% due to high copper levels in the feedwater.
August 30	Unit shut down due to inoperable reactor water level instruments on the '2B' condensing chamber.
September 5	Unit startup.
September 6	Unit shut down from 26% power due to a leak of EHC fluid from the #4 turbine bypass valve.
September 8	Unit startup.
September 11	Power held at 80% due to high copper levels in the feedwater.
September 13	Breaker in the north substation fails to open completely causing a fire.
September 15	Power reduced to 60% for control pattern adjustment.
September 16	Power held at 80% for the remainder of the period due to high copper levels in the feedwater.

Unit 3

August 14	Reactor power at 100%.
August 17	Power reduced to 65% to check and repair leaky condenser tubes.
August 20	Power at 100%.
September 6	Power reduced to 65% to check and repair leaky condenser tubes.
September 7	Power further reduced to 45% to check and repair leaky condenser tubes.
September 10	Power reaches 84% but is reduced to 50% due to high conductivity in the feedwater.
September 14	Power remains at 100% through the end of the period.

ATTACHMENT II

TABLE OF ACRONYMS

ARI	Alternate rod insertion
CS	Core spray
ECCS	Emergency core cooling system
EDG	Emergency diesel generator
EHC	Electro-hydraulic control
ENS	Emergency notification system
ESF	Engineered safety feature
ESW	Emergency service water
EWR	Engineering work request
F	Fahrenheit
FAR	Failure analysis report
GE	General Electric
HPCI	High pressure coolant injection
HPSW	High pressure service water
IP	Installation procedure
LER	Licensee event report
LOCA	Loss of coolant accident
LPCI	Low pressure coolant injection
MCC	Motor control center
MG	Motor generator
MRF	Maintenance request form
MSIV	Main steam isolation valve
NCR	Nonconformance report
PCIS	Primary containment isolation system
PM	Preventive maintenance
PORC	Plant Operations Review Committee
RCIC	Reactor core isolation cooling
RHR	Residual heat removal
RPS	Reactor protection system
RPT	Recirculation pump trip
RWCU	Reactor water clean-up
RWP	Radiation work permit
SGTS	Standby gas treatment system
SRV	Safety relief valve
STA	Shift technical advisor
SSV	Shift Supervisor
SSFI	Safety system functional inspection
ST	Surveillance test
TAP	TMI Task Action Plan
TPA	Temporary plant alteration

TS	Technical Specification
TS LCO	Technical Specification limiting condition for operation
VDC	Volts-direct current

ATTACHMENT III

SURVEILLANCE TEST REVIEW AND OBSERVATION

The inspector observed or reviewed the results of the following surveillance tests:

- ST 8.1.13, "Diesel Generator Main Fuel Oil Storage Tank Sampling and Analysis," performed on 8/2/90.
- ST 8.1.16, "Emergency Diesel Generator Main Fuel Oil Storage Tank Water Removal," performed on 5/31/90, 6/28/90 and 2/26/90.
- ST 8.1.7, "Main Tank Diesel Fuel Analysis," performed monthly from 1/89 to 9/89.
- ST 6.11-3, "RCIC Pump, Valve, Flow & Cooler," performed on 9/10/90.
- ST 1.8, "Automatic Depressurization System (ADS) "A" Logic System Functional," performed on 9/10/90.
- ST 1.9, "Automatic Depressurization System (ADS) "B" Logic System Functional," performed on 9/11/90.
- ST 6.6.1, "Daily Core Spray "A" System & Cooler Operability," performed on 9/11/90.
- ST 6.7.1, "Daily Core Spray "B" System & Cooler Operability," performed on 9/11/90.
- ST 6.8.1, "Daily RHR "A" System and Unit Cooler Operability," performed on 9/11/90.
- ST 6.9.1, "Daily RHR "B" System and Unit Cooler Operability," performed on 9/11/90.
- ST 6.5.1, "HPCI Auxiliary Oil Pump Surveillance," performed twice on 9/10/90.