U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No. 50-277/89-16 License No. DPR-44
50-278/89-16 DPR-56

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

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

Inspection At: Delta, Pennsylvania

Dates: May 7 - June 17, 1989

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Reviewed By: T. Kenny for 6/22/89
J. H. Williams, Project Engineer date

Approved By: T. Kenny 6/22/89
T. Kenny, Acting Chief, date
Reactor Projects Section 2A,
Division of Reactor Projects

Summary

Areas Inspected: Routine, on site regular, backshift and deep backshift special restart team and resident inspection (821 hours Unit 2; 232 hours Unit 3) of accessible portions of Unit 2 and 3, Unit 2 power ascension transient testing, Unit 2 steady state operation at the 35% power plateau, operational safety, radiation protection, physical security, control room activities, licensee events, surveillance testing, Unit 3 refueling and outage activities, maintenance, and outstanding items.

Results: One violation associated with failure to follow modification installation, QC inspection and acceptance testing procedures was identified (sections 6.2.1 and 11.2). Two other NRC identified violations were identified; however, they met the criteria for not issuing a Notice of Violation. One was

associated with emergency core cooling system room drains (section 5.4.1) and the other was associated with high radiation door controls (section 5.4.2). Two examples of a licensee identified violation for missed Technical Specification surveillance requirements were also noted (section 6.2.2). Several events, including an automatic reactor trip, were reviewed (section 4.2). NRC shift coverage observations determined that: (1) licensed operator performance was adequate and control room activities were formally conducted, with one minor exception, (section 5.2); (2) logkeeping (section 5.3), shift turnover and communications (section 5.5), and control room staffing and training (section 5.6) were adequate; (3) Technical Specification (TS) compliance, reportability (section 5.7), and response to off-normal conditions (section 5.10) were conservative; (4) test and special evolution control (section 5.8) and teamwork (section 5.11) were effective; and, (5) procedure adherence by licensed control room operators was good; however, several procedural errors by non-licensed operators, reactor engineers and health physics personnel occurred (see section 5.9). Security and operations response to a bomb threat was timely and conservative actions were taken (section 10.2). Plant Management was noted as being involved in plant operations (section 11.1) and operations oversight continued to be effective (section 11.4). An increased maintenance backlog has occurred as indicated by control room annunciators in an alarmed condition and malfunctioning instruments. Licensee self assessment capability was demonstrated as evidenced by the Nuclear Review Board Meeting (section 4.3), the Station Review Meeting conducted on June 9, 1989, and the Management Oversight Team Meeting (section 11.3).

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DETAILS

1.0 Persons Contacted

*J. W. Austin, Superintendent, Modifications
G. A. Bird, Nuclear Security Specialist
J. B. Cotton, Superintendent, Operations
*T. E. Cribbe, Regulatory Engineer
G. F. Daebeler, Superintendent, Technical
*J. F. Franz, Plant Manager
D. P. LeQuia, Superintendent Services
G. Lipscy, Power Ascension Manager
D. R. Meyers, Support Manager
J. T. Netzer, Superintendent, Planning, Scheduling and Reporting
D. L. Oltmans, Station Chemist
F. W. Polaski, Assistant Superintendent, Operations
K. P. Powers, Peach Bottom Project Manager
*J. M. Pratt, Manager, Peach Bottom QA
G. R. Rainey, Superintendent, Maintenance
*P. Sawyer, Acting Senior Health Physicist
D. M. Smith, Vice President, Peach Bottom Atomic Power Station

Other licensee and contractor employees including all six Shift Managers were also contacted.

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

2.0 Facility and Unit Status

2.1 Unit 2

This inspection period began with Unit 2 at rated pressure and at 3% power. A High Pressure Coolant Injection (HPCI) system wiring error was being reviewed (see section 6.2.1). HPCI was subsequently tested satisfactorily from the alternate shutdown panel on May 8, 1989.

Safety relief valve (SRV) testing was performed on May 9, 1989; however, SRV 71L failed to reclose initially and three SRVs had position indication problems. A drywell inspection at 450 psig reactor pressure occurred on May 10, 1989. One valve had a packing steam leak which was repaired. The licensee concluded that SRV 71L required replacement during subsequent SRV testing on May 11, 1989. The licensee shut down Unit 2 on May 11, 1989. SRV 71L was replaced and the unit restarted on May 13, 1989. SRV retesting was completed satisfactorily on May 14, 1989 (see section 7.4).

During reactor heatup to rated conditions on May 14, 1989, problems were noted with the electro-hydraulic control (EHC) system. The reactor was taken subcritical and the EHC system was repaired (see

section 4.2.1). The reactor was restarted and the reactor achieved rated pressure conditions (920 psig) on May 15, 1989.

On May 19, 1989, at 7:22 a.m., the Unit 2 reactor automatically tripped from about 20% power. The cause of the trip was a failed "three element/single element" control switch in the feedwater level control system. This malfunction resulted in a low reactor water level trip. Safety systems reacted automatically to this condition and licensee emergency actions were appropriate. Upon completion of the licensee's root cause analysis and corrective actions, Unit 2 restarted on May 21, 1989 (see section 4.2.2).

On May 22, 1989, the turbine generator was started up and synchronized with the grid at 21% reactor power later that day. A malfunction in the offgas recombiner system caused the licensee to shut down the turbine generator and reduce power to 5%. The licensee traced the problem to a high steam flow input combined with a restricted drain line from the offgas recombiner condenser (see section 4.2.3). The licensee subsequently restarted the turbine generator and synchronized to the grid on May 24, 1989. Successful turbine generator overspeed trip testing was completed on May 25, 1989.

Power ascension continued to 33% power during the remainder of the period. During the period May 25 to June 1, 1989, the licensee dealt with problems associated with the traversing in-core probe system, with the drywell to torus bypass leakage test (see section 7.5) and with a failed potential transformer in the emergency electrical E-22 bus cubicle (see section 4.2.5). On June 1, 1989, the plant attained 33% power. This power level is the licensee's administrative limit for the NRC's modified Order which requires a 35% reactor power hold point.

2.2 Unit 3

The licensee continued the seventh refueling outage on Unit 3, which began October 1, 1987, including maintenance and modification activities. Repairs to the reactor pressure vessel manway access cover began on June 5, 1989. The next milestone for Unit 3 is the control rod drive exchange.

2.3 Common

The annual emergency plan exercise was held on June 14, 1989. The exercise was evaluated by an NRC team.

3.0 Previous Inspection Item Update (92701, 92702)

3.1 (Closed) Unresolved Item (277/88-28-04; 278/88-28-04). This item pertains to the lack of documentation to verify the completion of the Nuclear Review Board (NRB) action items by licensee management. The

inspector reviewed various minutes of NRB meetings and documentation supporting the closure of the NRB's action items for Units 2 and 3, and found them satisfactory. Review of the current listing of the Commitment Tracking System indicated that there are no outstanding NRB open items pending resolution by Peach Bottom management. Based on review and discussion with licensee representatives, the inspector determined that licensee action was adequate. This item is considered closed.

3.2 (Closed) Unresolved Item (277/89-07-10; 278/89-07-10). This item pertains to the misapplication of fuses in 125 VDC panel 2BD306 circuits 29-BD-30604 and 29-BD-30605 (Unit 2), and panel 3DD306 circuit 29-3DD-30605 (Unit 3). In accordance with single line diagram E-26, Sheet 1, Revision 1, these fuses were specified as type "FRN" 30 Amp, but the installed fuses were type "NON" and "KON".

The licensee investigated the causes of the above discrepancies and determined that the single line diagram was revised to meet 10 CFR 50, Appendix R, Fire Protection requirements. However, the replacement of these fuses was not accomplished and there was no firm schedule to replace these fuses at that time. Later, these fuses were replaced with correct fuses as designated in single line diagram E-26. The inspector verified that the fuses currently installed in the above circuits are type "FRN-R-30". Also, to preclude a similar misapplication from happening in the future, the licensee is in the process of establishing a plant wide listing of approved fuses used in electrical protective devices. The licensee will verify and update the status of all such fuses.

Based on the above review and discussion with the cognizant plant support engineers, the inspector determined that the licensee's corrective action was adequate. This unresolved item is closed.

3.3 (Closed) Unresolved Item (277/89-15-02). High Pressure Coolant Injection system modification system wiring error (see section 6.2.1).

4.0 Plant Operations Review

4.1 Operational Safety Verification and Station Tours (71707)

The inspector completed the requirements of NRC Inspection Procedure 71707, "Operational Safety Verification," by direct observation of activities and equipment, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety system status and limiting conditions for operation, corrective actions, and review of facility records and logs. Specific comments and conclusions are addressed in section 5.0.

The inspectors performed 700 total hours of on site backshift time, including 330 hours of deep backshift and weekend tours of the

facility. Deep backshift inspections included around-the-clock coverage from May 7 to June 2, 1989.

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

4.2.1 Unit 2 Electro-Hydraulic Control (EHC) Malfunction on May 14, 1989

On May 14, 1989, during reactor heatup and pressurization to rated (920 psig), abnormalities were experienced with the electro-hydraulic control (EHC) system. The EHC pressure setpoint controller malfunctioned and EHC indicated pressure (reactor steam) was about 80 psi lower than actual reactor pressure. The licensee decided to insert control rods and to depressurize at 8:40 p.m. on May 14, 1989, in order to troubleshoot the EHC system while the reactor was subcritical. The Superintendent of Operations reported to the site and proceeded to the control room to assist the operations shift.

Licensee troubleshooting activities identified a loose gear on the EHC setpoint controller drive motor as the cause of the malfunction. The gear was tightened, and other similar devices were checked satisfactorily. Calibration checks for the EHC pressure transmitters PT 2864 and 2865 found them within tolerance; however, they were recalibrated. A management meeting was held in the control room to discuss the non-linear calibration curve for these PTs versus actual reactor pressure. A GE engineer stated that a 50 psi deviation at mid-range (450-500 psig) was normal. The licensee restarted the reactor and criticality was attained at 11:23 a.m. on May 15, 1989.

The inspector monitored licensee actions during problem identification and troubleshooting activities. The inspector determined that the licensee acted conservatively in taking the reactor subcritical without EHC available. Operations management was also noted as being involved in operations oversight and direction. The inspector attended the EHC management meeting and noted that plant management was also involved in this event. No unacceptable conditions were noted.

4.2.2 Unit 2 Automatic Reactor Scram on May 19, 1989

The Unit 2 reactor automatically tripped from about 20% power at 7:22 a.m. on May 19, 1989. The trip occurred after the reactor operator shifted the feedwater level control system (FWLCS) from single element to three element control. This action caused the one operating reactor feed pump to increase speed.

The increased feedwater flow resulted in a low suction pressure trip of the feed pump.

Reactor level then decreased to the automatic trip and containment isolation setpoint of 0 inches. Before a feed pump could be returned to service, the water level continued to decrease to about minus 42 inches. The alternate rod insertion (ARI) system actuated and both reactor recirculation pumps tripped. The high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems did not automatically initiate. These safety systems all actuate at a reactor level of minus 48 inches; however, HPCI and RCIC did not actuate because their trip logic is different. The licensee recovered reactor water level with the reactor feed pump, reset the trip and containment isolations, and made an ENS call at 8:16 a.m.

The licensee determined that the root cause of the trip was a defective single to three element switch in the FWLCS. When the switch was placed in the three element position, its contacts apparently did not close, resulting in a perceived low level condition. The operating feed pump increased speed and feed flow, causing a low suction pressure trip. Water level decreased to -42 inches resulting in a reactor trip at zero inches. The licensee confirmed that the HPCI and RCIC system initiation logic at -48 inches was different than the alternate rod insertion and the recirculation pump trip logic. An ENS call was made at 10:17 a.m. on May 20, 1989, to report that the reason RCIC and HPCI did not auto start was because the logic was not fully actuated. Other ENS calls were made at 2:45 p.m. on May 20, 1989, to report inoperability of the 2A core spray loop minimum flow valve while in hot shutdown; and, at 10:40 p.m., on May 20, 1989, to report that this core spray valve and the respective loop were returned to service.

The inspector was in the control room at the time of the reactor trip. The inspector noted that there was a discussion between the reactor operator (RO) and Shift Supervisor (SS) prior to moving the switch to the three element position of FWLCS operation. This operation was being performed in accordance with GP-2, "Plant Startup" and the system operating (SO) procedure. When the FWLCS malfunction occurred, operator response was adequate. The RO informed the SS of the problem and impending trip. The RO was unable to reset a feed pump to recover level prior to the trip. The SS adequately implemented the transient response implementation plan (TRIP) or emergency operating procedures T-100, T-101, and T-99. The Shift Manager was

conducting turnover for non-licensed operators and he reported to the control room a few minutes after the trip occurred.

After the unit was stabilized in the hot shutdown condition, the inspector reviewed control room instruments, computer alarm print outs and the preliminary upset report. The operators on shift were interviewed and the inspector attended several trip debrief/root cause analysis meetings.

During trip recovery, a fire was reported to the control room at 8:20 a.m. This required the fire brigade to be called out. An electrical cord was overheating in the turbine building. Licensee actions were adequate in response to the fire.

After the unit was stabilized, the licensee noted that the control room total feedwater flow recorder was not operating. It was drawing a straight line ink trace. The difference between total steam and feedwater flow was small. However, the individual feedwater flow recorder was operating and indicating correct feedwater flow. The licensee repaired the total feedwater flow recorder.

Licensee actions in response to this trip included the following:

- -- performing a root cause analysis and completing corrective actions,
- -- checking the FWLCS calibrations,
- -- PORC review of the completed GP-18 "Scram Review Procedure",
- -- completing operations incident report 2-89-51 on the trip,
- -- determining how the FWLCS was to be operated and making the necessary procedure changes,
- -- comparing the HPCI/RCIC initiation logic with the alternate rod insertion logic, and
- -- briefing the NRC restart team prior to startup.

Licensee post trip review and analysis determined that failure of the three element to single element switch was the root cause of the event. Licensee testing found that the switch did not close completely at all times when placed in the three element position. In addition, the switch's application is being reviewed. A new switch was installed in the control room panel. Other similar switches were also checked and no abnormalities were noted.

Calibration checks on the FWLCS electronic cards found that two cards (104 and 107) associated with feed flow amplification were out of calibration. The licensee recalibrated these cards and determined that they had no effect on the transient.

The licensee reviewed the HPCI/RCIC initiation logic and recent associated surveillance test of instrumentation setpoints. Reactor water level decreased to -42 inches as indicated by three separate control room chart recorders. The "as found" trip setpoints for the four trip logics (A,B,C,D) indicated that the order of logic initiation was A-B-D-C, with a maximum difference of about 2.5 inches. Also, all four logic trip devices were within the test acceptance criteria of -42 to -45 inches and all were within Technical Specification limits of greater than -48 inches. The alternate rod insertion logic was confirmed to be:

(A or C) and (B or D)

The HPCI/RCIC initiation logic was confirmed to be:

(A or B) and (C or D).

The licensee determined that the A and B logic initiated, and the C and D did not initiate. This explains why alternate rod insertion actuated and why HPCI/RCIC did not.

The NRC restart staff reviewed the licensee's root cause analysis of the trip; monitored troubleshooting and repair activities; and, reviewed the licensee's upset and incident reports (2-89-51), GP-18 reactor trip review procedure, and corrective actions. The NRC restart staff provided 24 hour coverage of licensee post trip and pre-startup activities.

The licensee restarted the unit on May 21, 1989, and criticality was achieved at 6:53 a.m. The FWLCS was subsequently shifted to three element control at 9:02 p.m. on May 25, 1989. Three element control of reactor water level was as expected in automatic FWLCS operation.

4.2.3 Offgas Recombiner Abnormality on May 22, 1989

At 12:56 p.m., on May 22, 1989, the turbine generator (TG) was synchronized with the grid at 21% reactor power. During afternoon shift on May 22, 1989, at about 8:15 p.m., high level and high pressure occurred in the offgas recombiner condenser. With the potential for problems with condenser vacuum, the licensee tripped the TG at 10:15 p.m., and reduced power to 5%

due to this offgas recombiner abnormality. During this transient, a small gaseous release occurred into the recombiner building and out through the Unit 3 reactor building ventilation stack. This release was calculated to be 1.67% of the whole body and 0.3% of the skin dose Technical Specification limits. The reactor remained at 5% power until troubleshooting and repairs to the offgas recombiner system were completed.

Licensee actions included a complete walkdown of the offgas and recombiner systems, review of operational data from the recombiner transient, review of the release flow path, inspection of the recombiner condenser for possible tube leaks, and review of the system design and operating procedures.

The licensee concluded that a high steam input (9200 versus 7500 pounds mass per hour) to the jet compressor caused high level and high pressure in the offgas condenser shell side. This caused a flow backup in the offgas stream and could have caused a loss of main condenser vacuum. No tube leaks were found in the recombiner condenser. The licensee confirmed the release path to be from the offgas recombiner condenser shell side relief valve to the recombiner building sumps and into the ventilation system. The licensee placed the offgas and recombiner systems back in service at 6:30 a.m. on May 24, 1989, to monitor its operation. No further difficulties were noted.

The inspector observed licensee actions in the control room and in the health physics office. The licensee evacuated the recombiner building as required by procedure ON-104, "Vent Stack High Radiation". Immediate and follow-up actions were consistent with procedures and were conservative. The inspector observed licensee troubleshooting activities and attended several meetings at which system operations were discussed. The inspector also walked down the affected system with the system engineer and the Plant Manager. The inspector concluded that the licensee took adequate immediate actions, determined the root cause and initiated appropriate corrective actions.

4.2.4 Unit 2 Torus Level Increase on May 26, 1989

At about midnight on May 26, 1989, the inspector noted an increasing level in the Unit 2 torus. Level was 14.75 ft. and was increasing slowly. The reactor operator (RO) had also noted the increase. Several minutes later the high level alarm occurred at 14.80 ft. The RO began to pump down the torus, and alerted the Shift Supervisor and Shift

Manager. All possible inputs into the torus were evaluated. The RO noted that the A loop of RHR was tested during the preceding shift and that the C RHR pump discharge check valve sometimes fails to fully seat. The RO sent a non-licensed operator to the C RHR room to check closed the external actuator arm on the check valve. Torus level peaked at 14.87 ft. which is below the TS limit and entry condition for T-102, "Containment Control" (14.90 ft.). The inspector calculated that the input from the RHR stayfull system via the condensate storage tank was about 15,000 gallons. This closely corresponded to an increase in torus level of about two inches (from 14.70 ft. to 14.87 ft.).

The inspector discussed the event with control room personnel. The Shift Manager directed the STA to write an incident report. Licensee corrective actions were adequate.

4.2.5 E-22 Emergency Bus Potential Transformer (PT) Failure on May 31, 1989

At about 5:10 a.m., on May 31, 1989, a guard and a non-licensed operator each reported an acrid smell in the E-22 4KV bus room. Shift management discussed corrective actions while the source of the smell was investigated. At 6:10 a.m., the fuses isolating the PTs in the E-222 breaker compartment were pulled and no abnormalities were found.

At shift turnover, at about 7:00 a.m., the oncoming licensee operations shift reviewed and discussed the situation, and prepared a contingency plan to shut down the reactor due to a possible anticipated transient caused by an inoperable E-22 bus. The E-22 bus may have had to be taken out of service to investigate this acrid odor in the switchgear cabinets. The E-22 bus supplies safety-related station load and control. According to the plan, the PT fuses were removed from circuit breaker E-22 bus compartment at 8:40 a.m. The plant generation support staff identified PT-2-54-1606 in the E-22 bus as damaged. The licensee entered a Technical Specification (TS) limiting condition for operation (LCO) in accordance with TS Table 3.2.B. TS Table 3.2.B is related to the availability of the 4KV emergency bus undervoltage relays and the 4KV emergency bus sequential loading relays for the core and containment cooling systems.

At 9:35 a.m., the E-22 4KV bus was returned to its original condition without any repair or replacement of damaged E-22 bus PT 1606. The NRC was notified via the ENS of a one hour notification due to an initiation of plant shut

down within 24 hours. The licensee initiated a maintenance request form (MRF) 8904467 to replace PT 1606 with a similar PT obtained from Unit 3. At 2:02 p.m., the licensee initiated a second TS LCO action statement, and the repair/replacement of the PT was completed by 2:27 p.m. System operability was verified and the E-22 bus was returned to service. The NRC was notified and the LCO was cleared at 2:30 p.m.

The inspector examined the failed PT (GE type JVM-3, 4400V/120V) during licensee troubleshooting. The inspector also observed replacement work and verified that QC performed an independent verification of quality control replacement activities for the PT. The inspector attended the licensee briefing and review of the contingency plan related to the E-22 bus PT replacement and the facility's Technical Specification constraints. The inspector concluded that licensee actions were conservative and no unacceptable conditions were noted.

4.2.6 Local Power Range Monitor (LPRM) Spiking

During the restart power testing program, Unit 2 experienced five LPRM detector failures of the 60 new NA-300 type detectors installed. The failures consisted of momentary spikes with indicated LPRM power level high enough to trip the reactor protection system (RPS) and generate a half reactor trip condition. Each time this occurred, the operating shift adequately responded to the half reactor trip, bypassed the malfunctioning LPRM, reset the RPS and verified the minimum number of LPRMs were operable. None of the 112 older LPRMs currently installed have exhibited this phenomenon.

Interviews with licensee personnel and GE representatives revealed that similar problems have occurred at other plants with NA-300 series type LPRMs. The detector vendor believes that the cause of this spiking is due to a uranium coating instability in the detector which produces a fine uranium powder with marginal adherence to remainder of coating. This powder is responsible for producing the random spikes as it breaks apart. The manufacturing process has since been changed to correct this coating instability and newer NA-300 detectors are not subject to this problem.

The vendor has found that by performing a voltage plateau curve test on the detector, the uranium powder is burned off the cathode and the spiking problem either stops or is reduced. The licensee is planning on running this plateau

curve test on all 60 of their NA-300 LPRMs. The inspector will review the results of those tests.

4.3 Nuclear Review Board (NRB) Meeting (40500)

The corporate Nuclear Review Board (NRB) held meeting number 241 at the Peach Bottom Station on May 11, 1989. The inspector attended the meeting and observed that a quorum (including the principal NRB members and NRB consultants) was present. The meeting was conducted in accordance with a detailed agenda which encompassed the scope of issues specified for NRB review in the Technical Specifications (TS). The inspector noted that the current NRB meeting frequency is three times greater than required by the TS.

Topics discussed included, but were not limited to the following: readiness of the plant to proceed with the startup test program; operating abnormalities; unanticipated deficiencies; the emergency cooling tower test results; voltage regulation study concerns; reports by the Plant Manager, the Shift Manager, Plant Services, and the Nuclear Services Division; reports on plant tours; LERs; PORC meeting minute reviews; Nuclear Quality Assurance audits; and ISEG activities.

The NRB considered the results of operating experience from an event at Limerick by reviewing the Peach Bottom program for use of hoists and cranes. The licensee demonstrated its self assessment/independent assessment capability by reviewing whether the generic implications of specific incidents are systematically considered. Consideration of generic implications, in this regard, would involve whether the root cause for given incidents is also applicable to other plant activities or equipment not involved in the specific incident. This topic was addressed by the Plant Manager and several of the consultants to the NRB. A consultant suggested that several LERs (2-89-02 and 2-89-04) offered no discussion of the generic implications of the subject incident and that such consideration should be given.

The inspector concluded that the NRB meeting appeared to be effective and no deviations from TS or procedural requirements were observed.

5.0 Shift Activities and Observations (71707, 71715)

5.1 NRC Shift Coverage

The NRC restart team began 24 hour continuous shift coverage on April 26, 1989 (see NRC inspection 277/89-15, 278/89-15). This inspection coverage continued until 11:00 p.m. on June 2, 1989, when the licensee had been at a steady state 35% power level for approximately 48 hours. During the Memorial Day weekend from 7:00 p.m. Saturday, May 27 until 7:00 p.m. Monday, May 29, 1989, continuous inspection

coverage was suspended due to steady-state plant conditions. During this period of non-continuous coverage, unscheduled random backshift inspections and tours were performed by the NRC restart team.

5.2 Operator Performance, Attentiveness and Formality

The inspectors routinely monitored licensed operator alertness, attentiveness and job performance in accordance with the requirements of the appropriate sections of the Operations Manual. No instances of operator inattentiveness were noted. Operational activities were conducted formally as noted during shift turnover, during routine control panel monitoring, and during off-normal and emergency situations. Several times during the shift coverage, inspectors noted that the unit reactor operator was performing administrative duties including answering the phone at the console, performing paperwork, etc. These duties could have the potential to distract an operator from his licensed duties. The inspector checked the Operations Manual section 7 which describes the frequency of panel checks. These required panel checks were performed. This item was also discussed with operations management who had also noted two instances of excessive administrative workload for reactor operators.

One instance of a brief loss of decorum by a Chief Operator (common unit reactor operator) was noted by the inspector at 10:20 a.m. on May 26, 1989. A discussion between the operator and the Shift Manager was in progress when the operator elevated his voice and used body/hand gestures. The duration of this episode was brief, i.e., a few seconds; and at no time was the operator inattentive to his common unit electrical/radiation monitoring panels. Following the outburst, the Shift Manager relieved the operator temporarily, and held a discussion in his office. After about ten minutes, the operator resumed his Chief Operator duties. After the meeting with the Shift Manager, the operator acted professionally in all his licensed duties and activities. Further follow-up and discussions with the operator, the Shift Manager, and operations management were held. The inspector concluded that the Shift Manager's actions were prudent and timely with respect to disciplining the operator. Apparently the outburst was caused by the operator's lack of understanding why the reactor pressure narrow range recorder was not being kept on-scale between 950-1050 psig. The reason for a change in operating the reactor pressure setpoint during startup in GP-2 was apparently not communicated to the operators. Licensee management reviewed this item and provided the technical reasons for this change to operating personnel. The inspector had no further questions at this time.

5.3 Logs and Records (71707)

The inspector reviewed logs and records for accuracy, completeness, abnormal conditions, significant operating changes and trends,

required entries, temporary plant alterations, conformance with Limiting Conditions for Operations, and proper reporting. The following logs and records were reviewed: Control Room Shift Supervisor Log, Reactor Engineering Logs, Unit 2 Reactor Operator Log, Unit 3 Reactor Operator Log, Chief Operator Log, STA Log, QC Shift Monitor Log, Radiation Work Permits, Locked Valve Log, Maintenance Request Forms, Temporary Plant Alteration Log, Special Procedures Log, Information Tag Log, Annunciator Mode Log, Plant Status List, and Ignition Source Control Checklists. Control Room logs were compared with Administrative Procedure A-7, Shift Operations, and the Operations Manual. Frequent initialing of entries by licensed operators, shift supervision, and licensee site management constituted evidence of licensee review.

Logkeeping by control room operators was generally thorough and accurate and in accordance with the Operations Manual. However, several minor instances of poor logkeeping were noted. During the 11 p.m. to 7 a.m. shift on May 16, 1989, the reactor operator did not log the noted operational problems with the position indication for the RCIC discharge check valve and the vibration alarm on the A reactor recirculation pump. Other occasions of poor logkeeping included two instances of write overs without initialling. These instances were discussed with the respective operator, and with shift and operations management. Further reviews of operator logs by the inspector indicated improvements.

5.4 Plant Tours

Each shift inspector conducted random tours of plant areas. These tours included inspection of plant equipment, non-licensed operator performance, work activities, health physics controls and security. During these tours the following items were noted.

5.4.1 Floor and Equipment Drains

During a tour of the Unit 2 Reactor Core Isolation Cooling (RCIC) system pump room on May 14, 1989, the inspector noted that equipment drain plug DRN-2-20B-2062 was removed. A tygon tube was connected between the RCIC pump pedestal drain and the equipment drain. No one was in the immediate area.

The inspector returned to the control room and obtained the most recent copy of GP-2, "Normal Plant Start-Up". Step 3.5.9 stated that all floor and equipment drains in the reactor building were closed per RT 13.9. The inspector questioned shift management concerning the type of administrative controls in effect. The temporary plant alteration (TPA) log did not contain an active TPA log entry that removed the plug.

Emergency core cooling system (ECCS) floor and equipment drain plugs are to be strictly controlled due to potential flood paths that could be opened between various ECCS rooms and the reactor building sump. Plugging floor and equipment drains was done in response to nonconformance report (NCR) P-88-123-213. Abnormal operating procedure AO-20A.1, "Removing a Floor Drain Plug, Equipment Drain Plug or Cleanout Cover," was also written so that these plugs could be removed without the use of a TPA. Shift management approval is needed to open a drain (as stated on a tag by each and every drain), and AO-20A.1 Attachment 1 is to be filled out. The procedure also states that anytime a drain is opened during reactor operation, a person must be stationed in the vicinity.

Failing to follow procedure AO-20A.1 is an NRC identified violation of Technical Specification 6.8.1 (277/89-16-01). However, no Notice of Violation will be issued in accordance with Enforcement Guidance Memorandum (EGM) 88-08, dated November 13, 1988. Discretion can be exercised if all of the following exists:

- -- Severity level V;
- -- Appropriate corrective actions were initiated prior to the close of the inspection;
- -- Non-willful; and
- -- Non-recurrent.

The licensee determined that the root cause of the violation was failing to inform shift operations of the new drain control policy and newly written procedure AO-20A.1.

Immediate corrective action consisted of replacing the drain plug. Corrective action to prevent recurrence consisted of holding a critique, writing an incident report, providing a letter to shift operations informing operators of the drain policy and AO-20A.1, and publishing this same information in the operations section newsletter. Future corrective action will consist of replacing AO-20A.1 with a less restrictive administrative procedure and hanging new tags on all the drains that will require shift management approval for entry into the drain system in accordance with a soon to be written administrative procedure.

The inspector reviewed the licensee's letter, operations section newsletter, the draft incident report and attended the critique. These corrective actions were found to be satisfactory. The inspector will review the remaining corrective actions in a future report.

5.4.2 High Radiation Area Control

At 9:55 p.m. on May 16, 1989, a shift inspector found a door labelled Locked High Radiation Area (HRA) opened with no individual providing positive door control. The door provided access to the containment personnel air lock and to the outboard main steam isolation valve (OBMSIV) room on the 135 foot elevation of the reactor building of Unit 2. The containment is a designated locked HRA and the OBMSIV room is potentially a locked HRA. The inspector immediately questioned nearby test engineers regarding whether any individuals were within the HRA and the responsibility for providing positive control for the opened door. The test engineers responded to the inspectors concern by calling security and health physics (HP). A security guard responded to the call, but took no action apparently because it was an HP problem. At 10:10 p.m. an HP technician arrived at the door. He explained that he had left the area 15 minutes earlier to start an air sample requested by his supervisor. He closed the open HRA door. The shift inspector, satisfied that an apparent immediate safety concern was corrected continued with his tour.

HP supervision had decided before plant restart to control HRAs by locking all the areas that had the potential to become high radiation areas during reactor power operations. This would allow a check of the new procedures for control of keys to locked HRAs to determine the adequacy of procedural controls and training efforts. However, this management decision was apparently ineffectively communicated to the HP technicians as some HP technicians were unaware of the decision. The technicians were confused over the existing posting and control of areas that were designated as locked HRAs. These areas would not become locked HRAs until the unit was at a higher power level. The attitude of the HP technicians led to reduced sensitivity to the posting and control of the designated locked HRAs.

The requirements for positive control of locked HRAs are specified in Technical Specification (TS) 6.13. In implementing these requirements, several procedures were not followed by licensee personnel:

- A-114, Rev. 0, "Locked High Radiation Controls"
- A-111, Rev. 0, "Duties and Responsibilities of Health Physics Personnel"
- A-116, Rev. 0, "Radiation Worker Responsibilities"
- HP-215, Rev. 5, "Establishing and Posting Controlled Areas"

The HP technician had the responsibility and authority to change posting based on radiation levels which he knew by surveys to be only a radiation area where the HP technician was directed to obtain an air sample by an HP supervisor, he did not change the posting but left the door open.

The incident was investigated by the licensee per procedure A-110, Rev. 2, "Radiological Occurrence Reports (ROR)". A completed ROR was reviewed by the inspector on May 19, 1989. The inspector determined that the immediate corrective actions were adequate. However, weaknesses were noted with both the long term corrective actions and the root cause analysis This was discussed with the licensee and the licensee indicated that a revised ROR would be initiated. The inspector noted that additional licensee commitments were made for root cause analysis and for corrective actions. The inspector considers these to be adequate.

Failure to follow procedures A-114, A-111, A-116 and HP-215 is an NRC identified violation of Technical Specification 6.8.1 (277/89-16-02). However, no Notice of Violation will be issued in accordance with Enforcement Guidance Memorandum (EGM) 88-08, dated November 13, 1988, since the following conditions exist:

- -- Severity level V;
- -- Appropriate corrective actions were initiated prior to the close of the inspection;
- -- Non-willful; and
- -- Non-recurrent.

The inspector had no further questions at this time.

5.5 Shift Turnover and Communications

Shift turnover activities, and operator control room and external verbal communications were observed. Shift turnover activities were professionally conducted. All required information was passed on either verbally or documented in the turnover checklist. Shift Manager turnover briefings were effective in informing operating personnel of plant status, problems and planned activities. Face-to-face communications were confirmed by repeating back the message to the originator. Operator communications with other work groups was also reviewed and was effective. No unacceptable conditions were noted.

5.6 Control Room Staffing and Training

Control room staffing was checked and found to be in accordance with Technical Specifications 6.2.2 and 10 CFR 50.54(k), (l), and (m). On May 19, 1989, the licensee informed the shift inspector that one reactor operator was temporarily removed from licensed duties due to an abnormal medical evaluation. The licensee replaced this operator with a reactor operator from another shift. This action maintained two fully qualified reactor operators on each of the six operating shifts. At the end of the period, the licensee maintained a staffing level of 18 senior reactor operators and 24 reactor operators for the six shifts.

Of the total number of licensed operators, 13 have restricted licenses. These individuals are working on their reactivity manipulations and operating time above 20% power. The licensee tracks completion of reactivity manipulations and the time spent with the reactor above 20% power. The Superintendent of Operations developed guidance to ensure that reactivity manipulations meet NUREG 1021 guidance. The inspector reviewed this guidance dated May 15, 1989, and concluded that NUREG 1021 guidance is being met. A tracking form (SP-1166, Exhibit T-1) is maintained for each individual. These forms are filed for each shift and maintained in the control room offices. Surveillance and routine test performance is also tracked for training purposes and documentation. The shift test coordinator maintains these records. When an operator with a restricted license completes his required items, the forms are assembled and sent to the training department. The inspector reviewed selected files and discussed program implementation with licensee personnel. No unacceptable conditions were noted.

5.7 Technical Specification (TS) Compliance and Reportability

The inspector reviewed the licensee's interpretation, implementation and use of the plant TS, including limiting conditions for operation and action statements. The inspector determined that the licensee was using conservatism in declaring TS related equipment inoperable due to system malfunctions. Examples included the following: safety relief valve 71L, the HPCI system, E-22 bus relays and protective trips, intermediate range monitors, the core spray minimum flow valve, a reactor water level recorder, and the RCIC flow controller. All required ENS reports were made on the ENS phone. No unacceptable conditions were noted.

5.8 Test and Special Evolution Control

The Shift Manager and Shift Test Coordinator provided the operations staff with effective pre-test briefings. Examples included the

following: safety relief valve 71L testing and subsequent retesting; feedwater and condensate pump startup, turbine generator startup, synchronization and overspeed testing; and HPCI/RCIC system testing. Tests and evolutions were well coordinated and professionally conducted. Several of the tests required temporary procedure changes. These changes were made in accordance with administrative controls. No unacceptable conditions were noted.

5.9 Procedure Adherence

Procedure adequacy, compliance, and adherence was reviewed. Control room licensed operators were adhering to operating procedures. No instances of procedural noncompliance by licensed operators were noted. The operators used the temporary change (TC) process when required. Permanent TCs were noted as being kept in the procedure cart in the control room. In a few instances, the operators displayed difficulty in locating a procedure that had a TC in effect. However, all TCs were eventually located and adequately implemented.

Two cases of procedure noncompliance were noted by the inspector during plant tours (see section 5.4). One was by a non-licensed operator due to lack of training and the other was by a health physics technician. The licensee also identified an instance where a non-licensed operator placed the drywell instrument nitrogen system in service without using the system operating procedure. The licensee reviewed this event, prepared incident report #2-89-48 and implemented corrective actions. The licensee determined that poor communications and misunderstanding by the operator contributed to this event. The inspector reviewed the incident report including the root cause and corrective actions, and discussed the item with shift and operations management personnel. The inspector concluded that the licensee's review was adequate.

The inspector observed a traversing in-core probe system (TIPS) operation in the control room on May 25, 1989. Two reactor engineers attempted to start the system but were unsuccessful. They then obtained system operating procedures S.5.4.1.A and S.5.4.1.B. One of the engineers missed a procedure step which requires waiting for the "Ready" light to come on before attempting to insert a detector. The light would not illuminate, but he pressed Auto Start to begin detector insertion. The system did not respond. A more experienced reactor engineer then informed the other two of several inadequacies in the TIPS procedures and advised them of the correct way to operate the system.

Procedure S.5.4.1.B is missing instructions for operating the X-Y plotter which caused the engineers to miss a trace during a TIPS run and necessitated repeating the run. Some of the TIPS panel labelling

is inconsistent with procedure terminology and several switches on the panels are either not labelled or have some unlabelled positions. The inspector was informed that a complete rewrite of the TIPS procedures is planned. In the interim, TIPS will be operated using the existing approved procedures. However, these procedures require the engineer's knowledge of the system for implementation. These deficiencies were identified to the licensee for corrective actions.

During surveillance test ST 6.1.2-1 performed on May 20, 1989, a non-licensed operator noted that he had an out of date revision of the procedure in use. He stopped the test, acquired the correct revision and performed the test satisfactorily. The reason for the out of date revision was that the ST was revised after the test was issued to operations for performance. The operator apparently did not check the ST index for the correct revision. However, he did later note the error and obtained the current ST revision.

The inspector determined that the way in which STs are issued could cause out of date revisions to be used. The ST coordinator issues a group of STs on Fridays prior to the week they are scheduled for performance. The ST Coordinator checks that each ST is current aginst the ST index. However, if a new revision was to be issued prior to ST performance and if the individual performing the ST failed to check the ST index, an outdated revision would be used. To correct this situation, a letter has been issued to remind individuals to check for current revisions. In addition, the ST Coordinator now checks for issued, out of date ST revisions when he receives a newly revised ST. These new licensee practices have noted two discrepancies during the last two weeks of this inspection period. The inspector had no further questions.

5.10 Response to Off-Normal Conditions

Operator response to off-normal conditions was timely, conservative, and in accordance with operating/emergency procedures. Examples included the following: reactor trip (section 4.2.2), EHC malfunction (section 4.2.1), loss of offgas recombiner (section 4.2.3), bomb threat (section 10.2), and E-22 bus room acrid smell (section 4.2.5).

Once the plant was stabilized, equipment troubleshooting, maintenance or repair, and equipment control was adequately performed. One instance of an unexpected result of a troubleshooting control form (TCF) occurred on May 23, 1989. During implementation of an approved TCF for the EHC system, the bypass valves opened unexpectedly. Operator response was adequate and the troubleshooting was suspended.

In general, operating problems or concerns eventually result in positive corrective action, such as procedure changes, troubleshooting, or maintenance.

5.11 Team Work

Each shift team was evaluated as being effective in accomplishing assigned tasks. The control room operations crew worked well together including coordination and direction of non-licensed operator activities (outside control room). The operators were also noted as working well with other site groups including: system and reactor engineers during testing and troubleshooting; maintenance personnel during equipment turnover, repair and testing; health physics personnel; and independent oversight groups and management.

5.12 Control Room Human Factors Engineering

The licensee completed a control room design review on February 28, 1986, which addressed many human engineering deficiencies (HED) in need of correction. More than 70% of these HEDs have since been corrected. The majority of these were corrected during Modification 2132. The inspector noted some additional minor items which appear to have been missed. Some examples include:

- -- low pressure turbine instruments are arranged in three rows corresponding to the three stages; except for inlet pressure indication.
- -- high pressure turbine first stage pressure indication is marked "Turbine Inlet" even though the documentation such as the FSAR refers to it as first stage pressure.
- -- oxygen sample switch (SS-2981) information label lists position 1 as middle torus and position 2 as upper torus. The actual positions are opposite.
- -- the primary containment isolation system status panel is not consistent in the arrangement of its indicating lights as to whether left is inboard or right is inboard.

Other examples exist but these are representative of the issue. The licensee is continuing to address this deficiency. Based on interviews with operators and management personnel, none of these discrepancies are considered to be significant. The licensee's progress will continue to be monitored and an update provided in a future report.

6.0 Review of Licensee Event Reports (LERs)

6.1 LER Review (90712)

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

LER No. LER Date Event Date	Subject
2-87-08, Rev. 1 5/25/89 5/29/87	Control room radiation monitor incorrect configuration
2-88-07, Rev. 1 05/24/89 10/26/88	Inadequate surveillance due to test procedure deficiency
*2-89-05 05/08/89 04/06/89	Motor control center terminal blocks missing hold down bolts (see NRC Inspection 277/89-15, 278/89-15)
*2-89-06 02/09/89 05/09/89	Containment atmosphere pneumatic tubing improperly installed (see NRC Inspections 277/89-81 and 15, 278/89-81 and 15)
*2-89-07 05/09/89 04/11/89	Excessive grease on emergency 4KV switchgear fuse clip contacts (see NRC Inspection 277/89-15, 278/89-15)
*2-89-08 05/15/89 04/15/89	Unit 2 containment isolation due to personnel error (see NRC Inspection 277/89-15, 278/89-15)
*2-89-09 06/05/89 05/05/89	HPCI wiring error
*2-89-10 06/09/89 05/14/89	RSCS Surveillance test missed

*2-89-11 05/30/89 04/26/89	Scram discharge volume valves surveillance test missed
03-88-03, Rev. 2 05/19/89 05/20/88	Unit 3 containment isolation due to RPS alternate feed trips

6.2 LER Follow-up (92700)

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

6.2.1 LER 2-89-09 concerns a licensee identified High Pressure Coolant Injection (HPCI) system wiring error discovered during surveillance operability testing on May 5, 1989. This operability test noted a lack of automatic governor valve control when HPCI was initially tested at 150 psig reactor pressure. The governor valve was full open with HPCI flow rate greater than the rated 6000 gpm. This condition also occurred when the HPCI flow controller was switched to manual. A wiring error was identified as an unresolved item (277/89-15-02) in a previous NRC Inspection 277/89-15, 278/89-15. (See section 3.3.)

The licensee performed an investigation and root cause analysis of the wiring error event. The licensee determined that the root cause of this event was failure to follow installation instructions by craft electricians during the implementation of Modification 5061. This modification installed an analog signal isolator which provides electrical isolation for fire protection concerns on the HPCI flow controller.

The installation error (by a contract journeyman electrician) resulted in a discrepancy in the configuration of the analog isolator. The polarity was reversed between the flow controller and the ramp generator. The causes of this discrepancy were as follows:

-- The electrician made field wiring connections using the industry standard practice of color matching (white to white, black to black, etc) in lieu of point to point as specified in installation procedure CD 5.3; and,
-- The electrician applied the industry standard practice of positive (+) to black and negative (-) to white when bench wiring the isolator without regard to the external wiring color convention.

The licensee also concluded that there were three contributing factors for this event:

-- Inadequate Inspection - post installation inspection was inadequate due to the failure of the Quality Control (QC) inspector to verify that the wiring installation was in accordance with the work instructions per procedure CD 5.3 and drawing.
-- Inadequate Field Wiring Check - The Field Installation Engineer used color coding to perform the point to point wiring check and therefore, failed to identify the installation errors. Communications used during the check were not specific with regard to wire number, cable number, or terminal point.
-- Inadequate Modification Acceptance Test (MAT) Procedure - MAT 5061 utilized Surveillance Procedure SI-2F-23-82-XXCO "Calibration Check of HPCI Flow Instruments" to verify the instrument loop from flow controller to ramp generator and signal converter. The SI procedure did not provide sufficient overlap of tested components to assure the required portions of the loop were tested.

Licensee corrective actions completed included the following:

-- HPCI was declared inoperable, redundant systems (reactor core isolation cooling and automatic depressurization) were satisfactorily tested, the wiring error was corrected, and HPCI was retested satisfactorily.
-- Supervisory personnel associated with implementation of modifications were briefed on this event.

-- The specific individuals involved in the installation, inspection, and testing of the isolator have been counseled on this event and the significance of the errors committed.
-- Installation Checklists for open electrical modifications have been changed to require the first line supervisor or the Site Lead Man (Job Foreman) to verify correct installation of the work prior to QC inspection.

In addition, corrective actions planned include:

-- Review the event with construction, inspection, test, and plant personnel associated with the implementation of modifications and MATS. Areas to be discussed include: adherence to procedures/instructions, wiring color standards, use of wire tags as a construction aide only, and attention to detail regardless of apparent simplicity of the installation.
-- Revise Construction Division Procedure, CD 5.3, "Procedure for the Installation of Electrical Equipment" to require the Site Lead Man to verify the correct installation of the work prior to QC inspection.
-- Enhance the modification process to further ensure that when an SI or other standard test is to be used to functionally test an electrical installation, the test adequately encompasses the components required to be tested.
-- Instruct personnel performing wiring checks in use of proper communications practices when performing wire checks or other similar tasks.

The inspector reviewed this LER; attended the licensee's critique and root cause meeting; reviewed operations incident report #2-89-44; reviewed the associated drawings and field installation; and, discussed this item with licensee engineering, management, and QA/QC personnel. The inspector concluded that the licensee performed an in-depth investigation and root cause analysis.

Technical Specification (TS) section 6.8.1 requires written procedures in accordance with ANSI N18.7-1972 and NRC Regulatory Guide 1.33. These documents require procedures for modification installation, inspection and testing. On May 5, 1989, during HPCI testing and troubleshooting the licensee noted that MOD 5061 was inadequately installed, inadequately inspected by QC, and inadequately tested by engineering and I&C personnel. These successive failures of modification installation, inspection and testing procedures are collectively a violation of TS 6.8.1

(277/89-16-03). The unresolved item is administratively closed (277/89-15-02).

Since the overall modification process has been noted as a weakness by both the licensee and the NRC (see NRC Inspection 277/89-81, 278/89-81), a Notice of Violation is being issued in this instance of a licensee identified violation.

6.2.2 LERs 2-89-10 and 11 are two examples of licensee identified violations for failure to perform Technical Specification (TS) surveillance requirements (277/89-16-04). LER 2-89-10 concerns a failure to test the rod sequence control system (RSCS) at 50% control rod density as required by TS 4.3.B.3.a during a Unit 2 reactor startup conducted on May 14, 1989. The licensee determined that a personnel error by shift management during review of GP-2, "Plant Startup" was the root cause. The licensee also determined that the event had no safety consequences based on the following considerations: RSCS was adequately backed up by both the control rod pull sheet per GP-2 and by an operable rod worth minimizer system; the missed surveillance test (ST 10.6.2) was satisfactorily performed two weeks prior to this discovery; ST 10.6.2 was performed satisfactorily upon discovery; and, the control rod pull sheets in GP-2 were adequately followed.

LER 2-89-11 concerns a failure to test the trip discharge volume vent and drain valves per ST 9.22 prior to Unit 2 startup on April 26, 1989. This testing is required by TS 4.3.A.2.c. The licensee determined that the cause was partly due to an omission from procedure GP-11C, "Mode Switch to Refuel" and partly due to the ST "Master File" requiring the test to be performed only at power. The licensee determined that the consequences of this item were minimal based on the following considerations: ST 9.22 was satisfactorily performed on April 29, 1989, when the missed test was identified; a historical review to 1985 noted that these valves have demonstrated adequate stroke times; and, that the valves are tested monthly when the TS require a quarterly test. The licensee reviewed the ST "Master File" and did not find any other missed STs.

The inspector reviewed licensee corrective actions and determined them to be adequate to prevent recurrence. The inspector determined that failure to perform TS surveillance requirements meet the criteria for licensee identified violations. The inspector had no further questions at this time.

7.0 Surveillance Testing (61726, 71707)

7.1 Surveillance Observation

The inspector observed surveillance tests to verify that testing had been properly scheduled, approved by shift supervision, control room operators were knowledgeable regarding testing in progress, approved procedures were being used, redundant systems or components were available for service as required, test instrumentation was calibrated, work was performed by qualified personnel, and test acceptance criteria were met. Daily surveillance tests including instrument channel checks, jet pump operability, and control rod operability were verified to be adequately performed. Parts of the tests listed in Attachment 1 were observed. Specific comments are noted in the following sections.

7.2 Core Spray System and Cooler Operability (ST 6.6.1 and ST 6.7.1)

Surveillance Test (ST) procedures 6.6.1 and 6.7.1 provide for the operability test of core spray system loops A and B and the room coolers when a core spray pump, a low pressure coolant injection (LPCI) subsystem, or a diesel generator is inoperable. The inspector witnessed a surveillance test of the core spray system performed based on the inoperability of the high pressure coolant injection (HPCI) in accordance with the requirements of Technical Specifications (TS) 3.5.C.2. Review of the procedure indicated that HPCI inoperability was not factored into the ST as a requirement for the core spray system surveillance test. The inspector discussed the concern with the cognizant operations staff and was informed that the subsequent revision of the procedure will incorporate the requirements delineated in TS 3.5.C.2.

During core spray loop A operability testing, full flow test motor operated valve MO-02-14-026A did not stroke fully closed with the 2C pump running. The licensee's investigation confirmed inadequate setting of the torque switch which prevented the valve from seating properly when stroking to the closed position. Maintenance request form (MRF) 89-03841 was initiated to adjust the torque switch. The torque switch thrust was readjusted to 66,000 ft-lbs and the valve was successfully stroked and proper valve seating was verified.

During core spray loop B operability testing, the control switch for normally open outside containment discharge valve MO-02-14-011B had to be held for approximately two seconds for the valve to stroke. Although no operability problem was encountered, the control room operator tagged the valve switch with an information tag. These core spray operability tests were adequately coordinated and interfaced between plant operations and test personnel. The tests were successfully completed and the test results were acceptable. The inspector did not have any further questions at this time.

7.3 HPCI Logic System Functional (ST1.1) and HPCI Flow Rate Test At 150 psig (ST 10.1)

ST 1.1 provides for the verification of the HPCI system logic to initiate and sustain the automatic operation of the HPCI system during a design basis accident condition. ST 10.1 provides for the operability test and performance of the HPCI system at 150 psig steam pressure. The inspector witnessed these HPCI system tests conducted in accordance with the STs. Two temporary changes (TCs) 89-0901 and 89-0902 were adequately initiated to modify the test steps of ST 1.1 in order to complete the test satisfactorily. During the HPCI operability test per ST 10.1, the system did not respond to the flow controller signal. Troubleshooting detected that the newly installed Analog Isolator was not properly field wired per an installation procedure contained in MOD 5061 for this installation (see section 6.2.1). The polarities were found reversed at the Analog Isolator resulting in erroneous output signal. As such, the HPCI governor valve had continuous signal of full open regardless of the system flow or the flow controller setpoint. However, during the surveillance test for system operability, the miswiring of the system was identified. The HPCI system was declared inoperable and the licensee notified the NRC in accordance with administrative procedures, A-31, Notification to the NRC, and A-86, Corrective Action. Subsequently, the wiring connection was modified and system operability was retested satisfactorily.

7.4 Relief Valves Manual Actuation (ST 10.4)

ST 10.4 provides for the inservice testing of the eleven main steam relief valves RV-2-01-71 A through L. The inspector witnessed the testing of the relief valves with reactor pressure at 175 psig and three bypass valves open. During the test, relief valves 71 A, G, H and L did not operate properly as required by the procedure. Troubleshooting indicated that the acoustic monitors that provide valve position were loose. In addition, the thermocouple sensor for relief valve 71 H was incorrectly wired. Subsequently, the acoustic monitors were tightened and the thermocouple wiring was modified. Retesting of relief valves 71 A, G and H was successful. However, relief valve 71 L failed to close initially during the retest. Consequently, the valve was declared inoperable in accordance with Technical Specification 3.6.D.1 and 2. A thirty day limiting condition for operation action statement was entered. Special Procedure SP-779 was initiated to allow ECCS to be defeated with the reactor mode switch in shutdown. Relief valve 71 L was replaced per maintenance procedure M-1.6 and MRF 8903976. This relief valve was retested successfully. Based on the review of the surveillance test and the valve replacement documentation, and discussion with the cognizant operations personnel, the inspector determined that licensee action was conservative, adequate and timely. The inspector did not have any further questions at this time.

7.5 Unit 2 Containment Bypass Test

In response to a drywell to torus low pressure alarm, the licensee decided to perform ST 12.6-1, "Primary Containment Drywell to Torus Bypass Test", Rev. 9. This test is required once per operating cycle by Technical Specifications (TS) 4.7.A.4.d and when the drywell to torus vacuum breakers indicate not fully seated per TS 3.7.4.B. Although neither of these TS criteria were met, the licensee initiated the test. Three tests were conducted between day shift May 29, 1989, and midnight shift May 30, 1989. All of these tests failed the acceptance criteria possibly indicating the existence of a bypass hole of greater than one inch in diameter. TS 3.7.4.B requires that the unit begin a shutdown 24 hours after an open vacuum breaker is noted with an equivalent bypass hole of one inch in diameter. Although the licensee did not have an open vacuum breaker, their actions were consistent with TS action requirements.

During day shift on May 30, 1989, licensee engineering, operations and management personnel met to discuss these test results. They concluded that the test method required improvements to ensure a higher differential pressure (greater than 0.4 psid) was maintained throughout the test. The three previous tests showed an excessive leak when differential pressure dropped below 0.25 psid. When the pressure was greater than 0.25 psid, the previous tests passed the acceptance criteria. The licensee revised the test to increase the pressure, to correct some minor deficiencies and to increase data collection to every five minutes.

A revised ST 12.6-1, Rev. 10, was performed between 10:37 p.m. May 30 and 12:42 a.m. May 31, 1989. Test results were satisfactory. All data points were calculated to be indicative of a hole less than the minimum of one inch in diameter.

The inspector witnessed each test; attended the licensee's management meeting on May 30, 1989; reviewed FSAR sections 5 and 14 and, reviewed the final test results. The inspector had no further questions and no unacceptable conditions were noted.

7.6 Scram Air Header High Pressure Alarm

On May 18, 1989, the inspector witnessed performance of ST 9.7, "MSIV Partial Closure and RPS Input Functional Test," Rev. 11, 4/16/89. The inspector noted that each time a half reactor trip was received, the 75 psig high pressure trip air header alarm would annunciate momentarily and then reset. When observing trip air header pressure on PI-312 in the control room, the pressure would rise to 76 psig immediately after a half reactor trip, and then slowly decrease back to the setpoint of 70 psig.

The inspector reviewed P&ID M-356, "Control Rod Drive (CRD) Hydraulic System - Part A," to determine the method of trip air header pressure control. According to the P&ID, pressure control valve

(PCV) 4239A or B should be positioned to regulate pressure at 70 psig. The inspector walked down the CRD system to determine the actual valve lineup. It appeared that both PCVs were in service at the same time which was in disagreement with the P&ID.

The inspector returned to the control room and obtained the most current check-off-list (COL) 3.1.A-2, "CRD Hydraulic System Startup," Rev. 2, which showed that both PCVs were in service at the same time. The inspector discussed this issue with shift operators who agreed that only one PCV should be valved in. However, the Shift Manager wanted to wait until day shift to make sure that the assumption was correct.

The licensee determined that the P&ID was correct and the COL was incorrect. The valve lineup was corrected such that only PCV-4239A was in service, and the COL was submitted for a revision. Operations also committed to observe the trip air header pressure during the next surveillance test that initiates half reactor trip testing.

On May 30, 1989, the inspector was observing ST 9.4, "Turbine Stop Valve Closure Functional," Rev. 27, 3/10/89, and ST 9.14, "Turbine Control Valve Fast Closure Scram Functional, Rev. 24, 3/20/89. Each time a "B" channel half reactor trip was received, the high pressure trip air header alarm would annunciate momentarily and then reset. The previous observations on May 18, 1989, led to the alarm during both and "A" and "B" half reactor trips. The licensee was questioned concerning this problem indicating in response that PCV-4239A has an internal problem. At the close of the inspection, the licensee was planning to take PCV-4239A out of service and place PCV-4239B in service and observe trip air header pressure during half reactor trips. The inspector will continue to follow this item in a future inspection.

8.0 Maintenance Activities (62703)

8.1 Routine Observations

The inspectors reviewed administrative controls and associated documentation, and observed portions of work for maintenance activities. Administrative controls checked included blocking permits, fire watches and ignition source controls, QA/QC involvement, radiological controls, plant conditions, Technical Specifications, equipment alignment and turnover information, post maintenance testing and reportability. Documents reviewed included maintenance procedures (M), maintenance request forms (MRF), item handling reports, radiation work permits (RWP), troubleshooting control forms (TCF), material certifications, and receipt inspections.

Document	Equipment	Date Observed
M1.27	Turbine Cross Around Reliefs	05/10/89
GP 2.2	Drywell Inspection	05/10/89
TCF	Emergency Cooling Water Pump Auto Start Alarm	05/10/89
M 1.6	Safety Relief Valve 71L	05/12/89
TCF	Intermediate Range Monitor E	05/14/89
TCF	EHC Pressure Control Swapping	05/21/89
MRF 89-4330 & 4388	Traversing In-Core Probes	05/25-28/89
TCF	Combined Intermediate Valves	05/26/89
TCF	E-22 Bus Potential Transformers	05/31/89
SP-1286	Unit 3 Reactor Vessel Manway Repair	06/6-9/89
MRF 89-4659	Unit 2 A Main Steam Line Radiation Monitor	06/07/89
MRF 89-4703	Unit 2 HPCI Leak Repair	06/15/89

No inadequacies were identified.

8.2 Unit 2 Maintenance Backlog

The inspector reviewed the current maintenance backlog. This included comparing a listing of off-normal control room annunciators and control room instrument deficiencies documented in the Unit 2 TRIPOD daily status report with the annunciators and instruments in the control room. Although the list generally matched the as-found condition, several differences were noted. Two instruments (FR-2522 and PR-8102A) were documented by a maintenance request form (MRF) without appearing on the list. Several instruments and annunciators were annotated on the list as needing MRF numbers even though their deficiency was identified as early as May 5, 1989. Several annunciators appear to be alarming spuriously yet are not identified with deficiency tags. Examples include:

- -- B RFPT HI VIBRATION (202/E-2)
- -- MAKEUP FILTER DRAIN REGENERATION TROUBLE (201/C-2)
- -- RHR HI TEMPERATURE (224/D-5)
- -- BLOWDOWN RELIEF VALVE HI TEMPERATURE (227/B-4)

On June 8, 1989, the inspector noted that there were 84 deficiency tags hanging on the Unit 2 control room panels. New deficiencies are apparently occurring at a faster rate than old ones are being corrected.

The inspector did not find any open maintenance items or MRFs that would make a safety system inoperable other than those already known and allowed to be out of service by Technical Specifications and documented in the LCO log.

9.0 Radiological Controls (71707)

9.1 Routine Observations

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

The inspector observed individuals frisking in accordance with health physics 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.

An NRC identified violation associated with high radiation controls was noted in section 5.4.2 of this report.

On May 15, 1989, the Senior Health Physicist or Radiation Protection Manager (RPM) resigned and was replaced by Paul Sawyer, acting Senior Health Physicist. The inspector reviewed the qualifications of the acting RPM and compared those qualifications against the criteria stated in Technical Specification 6.3.1, Facility Staff Qualifications; in ANSI N18.1-1971; and, in Regulatory Guide 1.8 (September 1975). The inspector concluded that the acting RPM met the appropriate qualifications.

9.2 Allegation Associated with Radiation Work Permits (RWP) (R1-A-89-0055)

On May 5, 1989, the resident inspector received an anonymous (via phone) allegation stating that a first line supervisor routinely fails to adhere to procedural requirements in RWP instructions and does not follow radiological safety precautions. The caller identified himself as a Health Physics (HP) technician and identified the supervisor by name. The alleger further stated that the identified individual was working in the plant without authorization of an RWP. The alleger also stated that when questioned by HP technicians, this individual denied violating any RWP. The alleger stated he would contact the NRC Resident Office with further information; however, this was never done.

The inspector evaluated this allegation by interviewing HP technicians who were at the various control points in the Unit 3 work areas on the specified day, and on days before and after the time frame of the allegation. In addition, a security trace of this individual was obtained. This trace indicated that the individual was in these specified areas. However, no RWP adherence concerns were noted.

The inspector also reviewed radiological occurrence reports for the time period and none were found. HP supervisory personnel were also interviewed and no concerns were raised. The inspector also reviewed the associated RWPs, inspected the Unit 3 work areas, and reviewed HP control point logs. Based on this review, the allegation could not be substantiated and it is considered closed.

10.0 Physical Security (71707)

10.1 Routine Observations

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

10.2 Bomb Threats on May 25, 1989

Two telephone calls were received at the Philadelphia Electric Company (PECo) Corporate Headquarters in Philadelphia, Pennsylvania, on May 25, 1989. The first call at 9:45 a.m. indicated that a van loaded with explosives would arrive at the Peach Bottom Atomic Power Station at 11:30 (no a.m. or p.m. given). Due to the nature of the PECo telephone system, the licensee was able to determine that the anonymous call had come from their internal CENTREX telephone system. The licensee evaluated the threat as non-credible at 11:00 a.m. However, as a precaution, bomb threat contingency procedures were implemented in and around the station which included barricades at the protected area access point, searches of vehicles in the owner-controlled area, establishing owner-controlled area vehicle access control points, posting armed officers at owner-controlled area substations, and positioning lookouts.

The second call at 4:48 p.m. indicated that "you stopped us today, we will get you tomorrow". This call was received by the PECo operator from an outside line.

The inspector was informed of the first event by the licensee at 10:25 a.m. on May 25, 1988. The licensee reported the event via the Emergency Notification System (ENS) at 12:30 p.m. The second event was also communicated to the inspector at 5:01 p.m. and the licensee made an ENS call at 5:55 p.m. per 10 CFR 73.71. The inspector and regional staff discussed these matters with the licensee. The licensee considered both threats non-credible. However, they continued to implement heightened security awareness.

The inspectors observed the licensee's actions from the control room and from various security facilities. The inspector toured the protected area, and vital areas, and verified the licensee's heightened security actions. Selected guards, security shift assistants and operations personnel were interviewed. The inspector also attended a guard mount (shift turnover meeting) at 5:45 am. on May 26, 1989. These contingent security measures were discussed at this guard mount. The inspector had no further questions at this time. The inspector concluded that the licensee's actions were appropriate for the circumstances.

11.0 Assurance of Quality

11.1 Plant Manager's Hold Point Meetings

The Plant Manager conducted hold point meetings on May 10 and 16, 1989, prior to releasing the plant from the following startup conditions:

-- 450 psig reactor pressure, and
-- reactor mode switch to "RUN", and
-- turbine - generator startup and synchronization.

These meetings allowed management to review past equipment malfunctions and problems, and to assess the readiness to proceed to the next startup plateau. The meetings were attended by all plant and station disciplines and organizations, including corporate and independent oversight groups. At the completion of each meeting, the licensee concluded that the plant was ready to proceed to the next startup plateau.

The inspector attended each meeting, noting that all site groups were represented. An adequate discussion of all previous hardware malfunctions that occurred was held. Following the reactor mode switch to "RUN" meeting on May 16, 1989, the licensee briefed the NRC Peach Bottom Restart Panel via the telephone. The inspector concluded that licensee plant management demonstrated a high assurance of quality in Peach Bottom operations.

11.2 High Pressure Coolant Injection (HPCI) System Wiring Error

A recent electrical modification to the HPCI flow controller occurred due to multiple personnel errors and failures (see section 6.2.1). These successive errors included an installation mistake by contractor electricians; and the failure of QC, of post modification electrical checkout, and of post modification acceptance testing to detect this error. The HPCI surveillance test did however detect this wiring error.

11.3 Management Oversight Team (MOT) Meeting on June 1, 1989

The licensee conducted a MOT review for the Unit 2 power ascension up to the 35% power plateau. The meeting was held on June 1, 1989, to evaluate this startup and transient period. Licensee personnel in attendance included MOT members (corporate and site managers, and an industry observer) and line management who made presentations.

The inspector attended the meeting and concluded that the licensee adequately evaluated their performance to date. This included both personnel and equipment evaluations. The licensee formulated strengths and weaknesses, defined follow-up action items, and concluded that Unit 2 was satisfactory to proceed to the 35% steady state period for approximately four weeks. The licensee identified the following two significant weaknesses:

(1) The maintenance backlog trend is increasing and needs to be addressed. Improvement is required to perform scheduled maintenance during the rolling 13 week schedules.
(2) Numerous surveillance tests are being performed in the grace period.

The licensee MOT will meet again after the four week steady state 35% period.

11.4 Operations Oversight

Plant and operation management including the Shift Manager, the Operations Superintendent and the Assistant Superintendent were noted as being effectively involved in plant operations. Specific examples included the following: EHC malfunction (4.2.1); reactor trip follow-up and root cause analysis (4.2.2); offgas recombiner abnormality (section 4.2.3); and, E-22 bus electrical problem (section 4.2.5).

12.0 NRC Bulletin and Information Notice (92703)

12.1 NRC Information Notice 89-44, Hydrogen Storage On the Roof of the Control Room

The inspector reviewed the impact of combustible gas storage on safety related structures. Peach Bottom has two combustible gas storage tanks. One is a 20,000 gallon liquid hydrogen tank at 150 psig for future hydrogen water chemistry control. The tank is located west of the site, 1800 feet from the control room intake. This hydrogen water chemistry system is part of a plant modification scheduled for implementation during the current Unit 2 cycle. The NRC reviewed this design in a safety evaluation report dated January 1987.

The other hydrogen storage facility is for the main generator cooling system. This consists of 24 gas cylinders (total volume of 553 cubic feet) at 2400 psig. It is located south of Unit 2 turbine building. The nearest safety related structure is the diesel generator building at a distance of 65 feet. The control room air intake is 520 feet from these hydrogen gas cylinders. No unacceptable conditions were noted.

12.2 Potential Misapplication of Certain Models of Pressure Transmitters (NRC Bulletin 80-16)

NRC Bulletin 80-16, "Potential Misapplication of Rosemount, Inc., Models 1151 and 1152 Pressure Transmitter with Either A or D Output Codes", was issued June 27, 1980. This bulletin informed licensees about a reversal in output signal level when the transmitters are subjected to pressures exceeding 140% of rated maximum pressure. A reversal could result in erroneous presssure indication for safety related applications. The bulletin suggested several ways the licensee could prevent erroneous indicated pressures. On July 30, 1980, the licensee responded to the bulletin. They committed to two methods of preventing this condition. The pressure transmitters were to be tested at the next calibration time for overpressure response. Also, training was provided for which control room pressure indicator was to be used.

The bulletin response was reviewed by a regional specialist, and was inspected for implementation by a resident inspector in 1980. The inspector again reviewed the PECO response letter, operating procedures, emergency operating procedures, calibration procedures, and the training records. The implementation of the licensee commitment was determined to be satisfactory. NRC Bulletin 80-16 is considered closed.

13.0 Unresolved Items

Unresolved items are items about which more information is required to ascertain whether they are acceptable violations or deviations. An unresolved item is discussed in section 5.9.

14.0 Management Meetings

14.1 Preliminary Inspection Findings (30703)

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

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

Date	Subject	Inspection Report No.	Reporting Inspector
6/13-15/89	Emergency Exercise	89-17/17	Gordon
6/8-8/89	Diesel Fuel Oil	89-16/16	Woodard

ATTACHMENT 1

Surveillance and Routine Tests (ST/RT) Observed

ST 10.16
ST 12.15.2-2
ST 1.1
ST 10.4
ST 8.1
RT 5.31
ST 3.3.1
ST 9.21-2
SI 2N-60D-SRM-A2CX
ST 4.6
ST 3.2.2
RT 5.13
RT 5.4
ST 26.7-2
ST 12.6-1
ST 9.4
ST 9.2
ST 9.19.2
RT 9.19.3
ST 16.35
ST 9.11
ST 20.004
RT 13.9
ST 1.13
ST 6.4
ST 9.12-1
ST 6.11-2
ST 12.15.6-2
ST 6.5-1
ST 6.5-2
ST 9.7
ST 7.6.1.K
RT 5.3
RT 5.9
ST 4.2
RT 5.0
ST 9.14
ST 3.5.1-2
ST 6.2-2
SI 2K-54-E12-XXFM
ST 2.5.40D
ST 6.6-F
ST 6.10-2
ST 6.1.2-1
ST 6.6.F-2
ST 19.14-5A
SI 2N-60D-B2CW
ST 10.6.2
ST 3.3.2
ST 6.5
ST 1.9
ST 13.60
RT 5.8
ST 13.47-2
ST 4.4
RT 5.14
ST 2.5.40A
ST 3.4.1
ST 9.10
ST/EP 11B
ST 4.6