U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee:	Philadelphia Electric Company Peach Bottom Atomic Power Station P. O. Box 195 Wayne, PA 19087-0195	
Facility Name:	Peach Bottom Atomic Power Station Units 2 and 3	
Dates:	February 3 - March 18, 1991	
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Date

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. Unit 2 refueling, maintenance and modifications activities were also evaluated.

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EXECUTIVE SUMMARY

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Plant Operations

Unit 3 operated without significant incident during the period, and minor events were handled promptly by the control room operators. Operations staff support of Unit 2 outage activities appeared generally effective, and a positive overall control room environment was maintained, despite implementation of significant Unit 2 control panel modifications.

Maintenance and Surveillance

The Unit 3 high pressure coolant injection system outage implemented by the licensee during the period was well planned and executed (Section 7.2).

Surveillance testing activities evaluated were consistently well performed. Planning and preparation for the Unit 2 reactor vessel hydrostatic test was effective and personnel performing the test were knowledgeable and cautious (Section 6.0).

Engineering and Technical Support

The technical content, associated safety evaluations, implementation instructions and the conduct of field installation activities reviewed by the inspectors during the period were of generally high quality (Section 5.3).

The inspectors identified that controlled drawings were not being updated to reflect installed temporary plant alterations (TPA) as required by the licensee's procedure. Additional weaknesses with the backlog, age and periodic review of TPAs were also noted. These problems were previously identified by licensee QA and third party audits, and revisions to the process and controlling procedure were under development. However, adequate action to resolve the specific deficiencies in the interim were not implemented (Section 5.2, NV4 91-08-03).

During a review of licensee temporary procedure changes (TC) the inspectors identified several examples of failure to properly process and incorporate TCs into the controlled procedure volumes and indexes in the main control room (Section 5.1, NV4 91-08-02).

The inspectors noted a number of Document Control Group procedure control, update and audit weaknesses which required management attention and corrective action. The licensee had previously identified actions needed to strengthen this area, and additional corrective actions were initiated in response to the inspector's observations (Section 5.1, UNR 91-08-01).

Safety Assessment/Quality Verification

The licensee continued to experience engineered safety feature actuations and plant events due to personnel error and procedural weakness. Review of these events by the inspectors indicates that no discernable adverse trend exists; but rather that a pattern of minor events and occurrences has persisted over the duration of the SALP period. The NRC believes that licensee assessment of the underlying root causes and implementation of corrective actions to address them is important in sustaining and building upon previously implemented program improvements. This issue was discussed during a February 25, 1991, management meeting in Region I (Section 4).

Licensee planning and coordination of the Unit 2 refueling outage appeared to be effective, resulting in improved performance of outage activities. Of particular note is the clear improvement in communications and cooperation evident in the conduct of daily outage activities.

DETAILS

1. 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 12 hours of deep backshift and weekend tours of the facility.

1.1 Operational Overview

Unit 2 was in refueling outage the entire period. Major outage activities included generator rebuild, recirculation pump motor generator set cleaning and rebuild, and "B" residual heat removal pump motor and impeller replacement. Major modifications included condenser tube replacement, emergency service water piping replacement, and replacement of the core spray, reactor core injection cooling, and high pressure coolant injection testable check valves. The Unit 2 process computer and control room consoles were also replaced. At the end of the period the reactor vessel hydrostatic test was complete, and control rod scram time and excess flow check valve testing was in process.

The period began with Unit 3 at full reactor power. Reactor power was reduced twice during the period, on February 15 and March 15, for control rod pattern adjustment. At the end of the period the reactor was at full power.

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

1.2 Plant Tours

The inspector toured all elevations of the Unit 2 drywell, torus, valve rooms, outboard main steam isolation valve room and main condenser. The inspector assessed housekeeping, general equipment conditions, and radiation protection controls. Work in progress was also observed. Overall, housekeeping in all areas was good. Drywell pre-entrance briefings provided by the Health Physics Group were thorough and radiation protection controls and practices were good. The inspector noted several minor equipment problems in the Unit 2 drywell. These items were discussed with the licensee and were corrected.

2. FOLLOW-UP OF PLANT EVENTS (93702, 37700, 90712)

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. The inspectors found that immediate licensee corrective actions were adequate. Long-term corrective actions will be included in the Licensee Event Reports (LER) associated with each event.

2.1 Unit 2 Primary Containment Isolation System and Standby Gas Treatment System Initiation Due to an Electrical Ground

On February 12, 1991, at 9:10 a.m., a partial Unit 2 primary containment isolation system (PCIS) actuation and standby gas treatment system (SGTS) start occurred during the removal of a blocking permit. All equipment responded as expected. The introduction of a ground previously created during unrelated modification work caused the actuations. The event was not detected by the plant operators until about 10:00 a.m., because related annunciators had been removed from service for outage work. The isolation was reset and SGTS was returned to a standby condition. The existence of the ground had been identified and troubleshooting initiated prior to the event. Troubleshooting was suspended before locating the exact source of the ground, and technicians attempted to isolate the affected portion of the circuit pending further investigation. The technicians did not consider the possibility of permit restoration, and did not fully isolate the ground from the PCIS circuitry. Following the event, shift management applied a new permit completely isolating the ground. The licensee counseled the involved plant staff and installation personnel concerning the event contributors. The licensee will issue a LER addressing this event.

2.2 Unit 2 Inadvertent Reactor Scram Due to Inadequate Blocking

On February 20, 1991, at about 1:10 p.m., a full Unit 2 reactor scram occurred. The unit was in refueling at the time with all control rods inserted. A trip had been inserted on the "B" reactor protection system (RPS) as part of routine surveillance test SI2M-60F-RT13-B3MO, "Response Time Test of APRM High Flux Scram Channels." Concurrently, a maintenance request form (MRF) to replace the power supply cable, and for work on the drive assembly of the "G" IRM was released for performance. The MRF scope originally included only the drive assembly work, and the work package and blocking were planned accordingly. The replacement of the power supply cord was added to the existing MRF without appropriate review and reassessment of the impact. The "G" IRM was bypassed as specified, so the work would not cause a half-scram on the "A" RPS channel. However, the power supply for the "G" IRM shares a common terminal with the "C" IRM power supply. When the electrician lifted the leads an inoperable trip on the "C" IRM, an "A" RPS half-scram and a full scram resulted.

Licensee investigation identified that an inadequate review by the shift management resulted in incorporating the additional maintenance action one month prior to performance of the MRF. At the time the review was performed, a full scram existed due to other outage work. Because of this a complete review of the work package, including electrical prints was not performed. Also, the electrician performing the work did not question the lifting of the power supply lead from the common terminal block when he noted two leads at the termination. Immediate licensee corrective actions included stressing the need for attention to detail when reviewing work packages and for ensuring complete reviews with shift management, establishing a practice precluding work on both RPS trains ... instructing the technicians not to lift leads from a terminal block unless ... effect of that action. The licensee is preparing a LER addressing this eve...

2.3 Unit 2 Loss of Shutdown Cooling Due to Inadequate Blocking

On February 21, 1991, at about 12:01 a.m., a shutdown cooling (SDC) isolation occurred when an auxiliary operator (AO) inadvertently grounded a lead in a control room panel while applying a blocking permit. The permit specified lifting and tagging a lead in panel 20C03. The lead is located in an extreme lower corner of the panel where numerous adjacent devices make identification of and access to the terminal strip very difficult. The lead was accidentally grounded when lifted, causing a fuse to blow and leading to the isolation of SDC return valve MO-2-10-25B. The drywell sump outboard isolation valve also isolated. The leads were relanded and the blown fuse replaced. The SDC isolation could not immediately be reset due to a pre-existing ground in the reset logic caused by ongoing modification work. The affected logic relay was manually reset in order to allow the SDC return valve to be opened. SDC was placed in service at 6:30 a.m. At the time of this event there were approximately 80 fuel bundles loaded in the reactor vessel. Vessel water temperature was 57 degrees Fahrenheit (F) and rose 5 degrees F while SDC was out of service. The fuel pool cooling system was operating at the time and there was insignificant decay heat load present. SDC could have been manually established at any time.

In this case the maintenance planners did not walkdown the permit prior to issuance to ensure that the task could be accomplished successfully. Also the individual applying the permit should have stopped the activity and reported the risk to shift management. Licensee immediate corrective action included rewriting the blocking permit, and initiating a review of the permit planning process to determine if additional controls are warranted. The licensee will issue a LER addressing this event.

2.4 Unit 3 High Pressure Coolant Injection System Inoperable Due to Insufficient Overspeed Trip Device Adjustment

On February 25, 1991, Unit 3 high pressure coolant injection (HPCI) was declared inoperable when the mechanical overspeed trip device (MOTD) did not operate as designed during performance of a routine surveillance test. The Unit was at 100% power and a seven day Limiting Condition of Operation was entered.

The cause of the inoperable MOTD was that the trip tappet assembly spring did not exert adequate force to maintain the tappet in the reset position. If the tappet is not maintained in the reset position the turbine stop valve can close, causing a trip of the turbine. A spring preload of at least 1.5 pounds is needed to ensure proper operation. The spring force decreased over time due to a design problem. The tappet assembly, made from a polyurethane polymer, swells in an oil environment. This swelling decreases the clearances around the tappet normally available for controlled leakage. The lower leak rates cause greater pressure buildup under the tappet, decreasing the spring preload. The spring force was readjusted, retested satisfactorily, and HPCI was returned to service later that day.

Several General Electric Service Information Letters discuss troubleshooting, surveillance, and resolution of spring force problems. These documents also indicate that a redesigned tappet assembly would be made available. The redesigned tappet assembly was installed on Unit 2 last outage. The Unit 3 tappet assembly will be changed during the next refueling outage in September 1991. In the interim the licensee has been performing Surveillance Procedure, ST 6.5.1, "HPCI Auxiliary Oil Pump Surveillance," Revision 3, weekly to determine the as-found spring force. If it is found to be less than 1.5 lbs, HPCI is declared inoperable. Previously the procedure included no instructions to provide for trending of the force and to prompt readjustment before it reached the limit of operability. The licensee changed the procedure to require notification of the responsible systems engineer when spring force is less than 2.0 lbs or more than 5.0 lbs. If the as-found condition is out of the specification, the spring tension will be readjusted. The inspector had no further questions.

3. UNIT 2 REFUELING OPERATIONS (71707, 61710, 93702, 61726)

During the previous inspection period the licensee completed Unit 2 core offload without incident. The inspectors' observation of those activities is documented in Inspection Report 91-03. During the current period the licensee initiated and completed core reload activities. Several personnel errors occurred during fuel movement, and procedural weaknesses were identified. These incidents are discussed in detail below.

3.1 Misplaced Fuel Bundles During Core Reload

During the current inspection period the licensee initiated and completed Unit 2 core reload. A significantly revised and streamlined process for performing, verifying and documenting fuel movement was recently developed by the licensee. This revised process was used for the first time at Peach Bottom during this outage. Among other changes the Nuclear Maintenance Division (NMD) now performs and supervises fuel movement. This process appeared to be effectively implemented during core offload. However, several errors were made during core reload operations which raised concern regarding the effectiveness of the licensee's procedure, communications and personnel attention to detail. These errors are discussed below:

- Step 270 of the Core Component Transfer Authorization Sheet (CCTAS) called for the fuel bundle in spent fuel pool (SFP) location XX-38 to be place into the reactor. On February 21, 1991, at about 10:00 p.m., the Licensed Senior Operator (LSO) on the refueling platform identified that this bundle was not in its specified SFP location. Core alterations were suspended. An investigation revealed that the bundle had been erroneously loaded into core location 27-12 during performance of CCTAS step 154 at 1:47 a.m. of the same day. CCTAS step 154 actually called for the bundle located in SFP location WW-38 to be moved. The licensee approved the changes to the fuel movement sequence needed to correct the error, and core reload operations were resumed. An in-house investigation was initiated. The inspector met with managers from Reactor Engineering (RE) and Nuclear Maintenance Division (NMD) on February 22 to discuss the root cause of the error and planned corrective. Licensee short-term corrective action was to counsel the individuals involved. The licensee felt that this was an isolated occurrence and would not be repeated.

- On February 22, 1991, at about 1:15 p.m., while performing step 330 of the CCTAS the fuel bundle in SFP location OO-64 was incorrectly loaded into core location 25-31. Step 330 actually called for the bundle in SFP QQ-64 to be loaded. This error was found at 6:00 a.m. on February 24 during performance of CCTAS step 623, which called for the bundle in SFP location OO-64 to be moved into the core. Core alterations were stopped and shift management, reactor engineering, and NMD supervisors were notified. The CCTAS was revised to allow correction of the misloaded bundle. The licensee found that poor CCTAS legibility contributed to the error. Less than adequate communications was also a contributor. Following the incident a letter was issued to all personnel involved in the operation discussing the importance of clear communications. Instructions were issued to the LSO and the control room Reactor Operator (RO) requiring that the LSO read the entire CCTAS step, and that the RO verify the information by comparison to his copy of the CCTAS. Also the CCTAS was reprinted using a new printer ribbon to improve legibility. Fuel movement was resumed.

- A third and a fourth error occurred on February 22, 1991, at 8:08 p.m. and 10:45 p.m respectively. These errors were made prior to discovery of the second error described above, but were not discovered before proceeding with fuel movement. The third error was identified at about 3:00 p.m on February 24. Fuel movement was suspended and the core and SFP were inspected, leading to discovery of the fourth error. In each of these cases a bundle with a SFP location designation of OO was mistakenly loaded instead of the correct QQ bundle. The licensee performed a 100% inspection of the core using a video camera and verified that all bundles, with the exception of the two remaining identified discrepancies, were correctly loaded. The CCTAS was revised to allow correction of the errors. Subsequently, fuel movement was suspended pending completion of the investigation and implementation of corrective action.

Following the identification of the fourth reload error the NRC staff concluded that a management meeting to discuss the licensee's review of the events and corrective actions was warranted prior to proceeding with core reload. A meeting was held at the Region I office on February 25, 1991. A listing of meeting attendees and a copy of the handout material supplied by the licensee are included as Attachments II and Attachment III respectively.

It appears that the procedure to control fuel movement did not contain adequate instructions to ensure consistent and effective communications between the LSO, the fuel handler and the RO. The content and quality of communication varied between operating crews. Also, no clear instructions regarding the implementation and documentation of verification activities were included in the procedure. The licensee revised the fuel handling procedure to address these deficiencies. Formal communications and verification practices were established and all personnel participating in the evolution were briefed on these changes prior to assuming their duties.

Following the licensee's presentation at the referenced management meeting, the NRC concluded that licensee corrective actions appeared adequate to preclude recurrence. Subsequently, the licensee resumed and completed core reload activities without incident. During the inspection exit meeting the inspector confirmed that the licensee is incorporating the lessons learned from these incidents into Limerick fuel movement procedures.

3.2 Refueling Moderator Temperature Limit Exceeded

On February 23, 1991, the licensee identified that Unit 2 moderator temperature had dropped well below the 68 degrees F assumed in the FSAR and the licensee's core reload analysis. The lower moderator temperature results in the addition of positive reactivity, and a decrease in shutdown margin. The licensee informed the NRC via ENS of the existence of the unanalyzed condition. F: reload was halted, and moderator temperature was raised above the 68 degree limit. The licensee performed a safety evaluation assessing the potential impact of exceeding this analytical limit and concluded that the decrease in shutdown margin was very minor, and of no safety significance.

Post-incident review identified that moderator temperature had been allowed to drop below 68 degrees during fuel movement on several occasions in the past. This practice was viewed as acceptable based on approval from the Fuels Management Group, documented briefly in a 1987 memorandum. At that time, and subsequently, the licensee did not recognize that this represented a change to the facility as described in the FSAR and, therefore, required review in accordance with 10 CFR 50.59. The NRC issued a violation, Severity Level III, for failure to perform evaluations as required by 10 CFR 50.59 during 1990 as a result of inspection 90-200. The licensee revised and strengthened this program during 1989 and 1990, resulting in significantly improved performance as described in inspection report 90-82. Because this issue was identified by the licensee, and predates both the NRC enforcement action and the program improvement, no additional enforcement action is warranted. The licensee's Technical Superintendent stated that the technical staff training program would be revised to include a session covering the licensing bases and the FSAR, and their relationship to plant functions and changes.

The licensee also identified that the minimum moderator temperature limit had not been incorporated into plant operating and fuel movement procedures as a prerequisite and for periodic monitoring, contributing to the event. The licensee revised plant procedures to incorporate the 68 degree limit. The licensee also stated that the ongoing procedure rewrite program included a review of the FSAR to determine relevant parameters and limitations for inclusion into the procedures. The licensee's Quality Assurance Manager informed the inspector that an Audit of the rewrite program, including evaluation of the FSAR information would be performed during the month of April, 1991. These actions appear adequate to address this weakness. The inspector had no further questions.

3.3 Full Core Verification Review

The inspector witnessed Unit 2 fuel reload operations, core verification activities, viewed the full core videotape and reviewed the licensee's procedure for final verification of proper fuel load. Surveillance T (ST) 12.10, Revision 3, "Core Post-Alteration Verification," is used to scan and video tape each row of fuel in the core; verifying that fuel location, orientation and seating are correct and that channel fasteners are present. An initial verification is performed by personnel on the refueling bridge while the taping is in progress. Following the initial verification the procedure calls for an independent verification to be performed using the video tapes. For both the initial and second verification a complete blank core map is filled in with bundle serial numbers and orientation and is compared to the desired core configuration. During the inspector's review the following discrepancies were noted:

- The video tapes produced were of poor quality. The inspector reviewed portions of these videos and found that some of the fuel bundle serial numbers were difficult to positively verify. When questioned, the personnel who performed the second verification stated that all fuel cells were correctly identified by repeated observation of tape segments. Additionally, the inspector was informed that the core was re-scanned and videotaped to verify that all channel fasteners were installed. Based on the discussions held with licensee personnel the inspector concluded that adequate controls were employed to ensure independent verification that fuel assemblies were in their proper location.

- The licensee identified that five fuel assemblies were not properly seated. Four of these bundles were removed to allow proper alignment and seating of the fuel support piece. Step 14 of ST 12.10 states that "After resolving all discrepancies listed on Data Sheet 1, have an independent verification of the bundle serial numbers, bundle orientation, bundle seating, and the existence of channel fasteners performed by the Fuel Management Section.... by viewing the "as left" video tapes. The verifier shall record the serial numbers and bundle orientations observed on the tape on a blank core map." The verifications required by this step were performed concurrent with efforts to correct the five fuel cells that were improperly seated. As a result, the sign-offs for independent verification of fuel cells in their proper location and proper orientation were made prior to all discrepancies being resolved. Although Fuel Management personnel retaped and verified the correct location of the assemblies moved, no sign-offs were made to reflect this nor was an additional blank core map filled out. In response to the inspectors question the licensee reperformed the verifications and generated the proper documentation.

- ST 12.10 includes steps requiring generation of several core maps and comparisons of these maps to identify discrepancies. Revision 3 to ST 12.10 was written in 1987. This revision added a step in the middle of the procedure. Procedure step numbers referenced in the text of subsequent steps were not changed to reflect the addition. This resulted in the procedure calling for different map comparisons. When pointed out by the inspector, the licensee processed a temporary change to update the procedure; however, not all incorrectly referenced steps were changed. The licensee's reactor engineering staff stated that the steps that were left as written, more accurately reflected the comparison that they felt should be performed. The inspector was concerned that by not restoring the procedure to its original form, or documenting all changes through the procedure revision process, in effect, a revision to the procedure had been implemented which circumvented the review process. The comparisons now prescribed by the procedure were not as originally intended. A second temporary procedure change was implemented to correct this deficiency. Other weaknesses related to processing and implementing TCs were identified during the inspection period and are discussed in Section 5.1 of this report. The licensee stated that training would be provided to all reactor engineers concerning the need for thoroughness when preparing and reviewing revisions to procedures.

The inspector concluded that licensee activities to verify correct core configuration were effective. Personnel involved were knowledgeable in their area of responsibility. While all verifications were performed satisfactorily from a technical standpoint, the inspector observed that personnel exhibited weaknesses as noted above in the careful use and revision of controlling procedures. This observation was discussed with licensee management.

4. ANALYSIS OF PEACH BOTTOM SALP CYCLE 12 EVENTS

4.1 Introduction

During the months of January and February 1991 the licensee experienced an apparent increasing trend in the number of reportable events. This raised concern among NRC Region I staff and management regarding the significance, meaning and underlying causes. During late February four fuel loading errors occurred in close succession during reload of the Unit 2 reactor core. In response to these errors, and in part due to the perceived trend noted above, a licensee/NRC management meeting was conducted in Region I to discuss the fuel loading errors. Subsequent to the meeting the inspectors performed an analysis of recent reportable events to determine if an adverse trend exists.

4.2 Analysis Approach

The Peach Bottom Resident Office maintains, for its own use, a database of significant events and issues. This database was expanded to include more detailed information regarding event root causes, responsible licensee groups, NRC inspection findings and all safety-related 50.72 reports. A number of ENS notifications made by the licensee during the period in question were excluded from the evaluation. These excluded notifications are a result of deviations from the licensee's Commonwealth Department of Environmental Resources (DER) permit and are not within the scope of NRC review.

A broad set of root cause categories was adopted for the purpose of simplifying the analysis. Pursuit of event contributors beyond this rough categorization is needed to fully understand each event. In most cases this more detailed assessment is documented in the individual inspection reports addressing the issues. Many events exhibit multiple root cause contributors and involve several licensee functional groups. For those events clearly involving more than one root cause and group, primary and secondary root causes and responsible groups were identified and considered in the review. Additional factors such as plant status, licensee internal corrective action system status, knowledge of program strengths and weaknesses and past problems were considered in reaching conclusions.

4.3 Identified Trends And Contributing Factors

Evaluation of events vs time shows three peaks of significance occurring in August/September, November and January/February. The August/September peak is dominated by three factors: 1) repeated control room ventilation actuations resulting from an intermittent electronics problem which was later identified and resolved; 2) repeated voltage transients on a single battery charger due to degradation of an electronics card support piece which was later identified and corrected, and 3) several design weaknesses identified by engineering as a result of transfer of Limerick experience to Peach Bottom and a licensee initiated SSFI. If Items 1 and 2 are consolidated into single events and the engineering issues are set aside due to the proactive nature of their identification, then the August/September period does not represent a significant peak.

The peaks in November and January/February occurred while the licensee was involved with major outages (Unit 3 mid-cycle and Unit 2 refueling). The two dominant root causes overall, but especially during these high work load periods, are personnel error and procedure weakness. It appears that the demands associated with these periods result in an increase in personnel error rate. Also, as personnel are stressed less time is available to carefully review and discuss procedures prior to performance of the activity. This increased reliance on the clarity and effectiveness of procedures may result in existing procedure weaknesses being surfaced. The distribution of personnel error and procedure weakness among licensee groups shows that while the Operations Department is involved in more events, all groups share in this problem. The underlying reasons are unclear. Potential contributors suggested through personnel interviews are implied schedule pressure, less than necessary direct supervisory involvement in work activities, and limited personnel experience and training specific to the assigned task.

Programmatic areas exhibiting multiple failures include: 1) surveillance test scheduling, performance and results review; 2) control and performance of I&C activities, and 3) permit and blocking development and application. Additionally, an overall weakness in personnel care and attention in performance of tasks appears to exist, despite licensee management efforts to address this area. These concerns were previously identified by the NRC inspection staff and licensee management and are addressed in inspection reports and the SALP Report.

4.4 Licensee Corrective Actions

Following the recent fuel loading errors the licensee took immediate steps to sensitize the station work staff to the importance of care in assessing and performing activities, and self-checking as a method to identify errors. These steps included a series of work stoppages for all-hands meetings, and letters from the site Vice President and Plant Manager. Ongoing management reinforcement of this concern has been evident. Following implementation of these short-term corrective actions, no reportable events occurred for the remainder of the inspection period. The licensee is performing an analysis of the events occurring during the past several months.

During the SALP period the licensee has initiated several aggressive programs intended to address identified weaknesses. They include:

- A surveillance test scheduling and results review program evaluation;
- A surveillance test procedure rewrite program;
- A maintenance self-assessment program;
- An I&C organizational and program review involving line personnel, QA, ISEG and representatives from Limerick;
- An "Attention to Detail Task Force" sponsored by the Plant Manager; and
- A permits and blocking process review effort.

In addition, the Vice President-Peach Bottom recently initiated an effort to establish "Items For The Nineties" on which the organization can focus improvement programs, and a detailed assessment of staff training program effectiveness. Also under development is a "Safety Barometer" which is intended to provide senior licensee management with an overall organizational performance indicator. The inspector has reviewed the scope and conduct of many of these licensee efforts as discussed in previous inspection reports. In all cases they were well focused. However, because these efforts are recent, most of the actions planned to correct the weaknesses identified have not been implemented. The inspectors will continue to monitor licensee actions in this area.

4.5 Conclusion

Based on inspection findings and observations during the course of the SALP period to date, and considering the analysis discussed above, the inspectors concluded that the licensee has demonstrated an overall improving trend with regard to organizational safety perspective and communications. Licensee senior management and most plant management are clearly and vocally committed to improved safety. However, this message apparently has not been adopted entirely at the working level, and in some cases the supervisory and middle management level. Review of the data does not indicate significant adverse trends. However, it is clear that continued licensee effort is needed to resolved the weaknesses underlying the events discussed above.

5. ENGINEERING AND TECHNICAL SUPPORT ACTIVITIES (39702, 37702, 37701)

The inspectors routinely monitor and assess licensee support staff activities. While performing these routine reviews the inspectors assessed a sample of licensee controlled procedures, procedure changes and temporary plant alterations. The inspectors identified several discrepancies, as detailed below. Also during this inspec... period the technical adequacy of several modifications was reviewed, with no deficiencies ...ntified.

5.1 Control of Plant Operating Procedures

A number of discrepancies pertaining to the control of procedures were identified during this inspection period. These discrepancies are listed below.

- The licensee issued Abnormal Operating (AO) Procedure AO 2D.2-3, "Recirculation MG Scoop Tube Manual Operation," to replace System Operating (SO) Procedure SO.2D.-7.A-2 with the same title, in response to a commitment made in the previous inspection period (Inspection Report 91-03). One week following the issuance of the new AO procedure, the inspector identified that the AO procedure, the original SO procedure, and the SO procedure with an outstanding temporary change (TC) were all present in the control room. The three procedures contained conflicting guidance.

  Approval for issuance of the AO and deletion the SO and TC was given on February 15, 1991, by the Plant Operational Review Committee (PORC). The licensee routinely updates procedures within 15 days of revision. Administrative Guideline AG-14, "Guideline for Control of Post-PORC Procedures," is used to designate "Hot" PORC approved procedures requiring processing within 24 hours. The AO was designated as "Hot" and placed in the control room within 24 hours. The SO procedure was not prioritized in the same manner which placed it into normal distribution per AG-12, "PORC Administration." The licensee stated that usually, revised procedures supersede like procedures and do not cross categories (i.e., SO to AO). Failure to recognize that the SO had been superseded and to appropriately prioritize it resulted in the problem. The licensee immediately removed the deleted SO procedures and committed to review and revise AG-14 to make provision for deletions of related documents.

  The inspector questioned the reactor operators to ascertain their awareness of the new AO procedure. The ROs related that the Shift Supervisor had informed them of the new procedure and that the item was published as an entry in the night orders. Based on operator knowledge and the plant conditions existing at the time of this incident, the safety significance of this event is low.

- The inspector audited one volume of controlled surveillance test (ST) procedures in the station library. Of 98 procedures which should have been in the volume per the ST procedure index, five procedures (STs 19.23.18, 21.8, 22.3, 22.4, and 22.5) were missing, pages 1 and 2 were missing from ST 24.1, and numerous STs were misfiled.

  In light of this finding, the inspector reviewed the results of the most recent licensee audits of the controlled ST procedures in the station library and the main control room conducted per Routine Test (RT) 9.11, "Controlled Procedures Inspection." On November 20, 1989, one volume of ST procedures in the station library was audited. Numerous deficiencies were identified including canceled procedures remaining in the book, misfiled procedures, and procedures not stamped "controlled." The errors were corrected, but the audit does not appear to have been expanded to include the other volumes of surveillance tests in the station library. An audit of the Chief Operator's (CO) ST procedures in the main control room was conducted on December 13, 1990. Numerous old revisions, canceled procedures, and misfiled procedures were identified. In addition, the procedures index was not the current issue. These errors appear to have been corrected. However, RT-9.11 does not require a 100% audit of the procedure category being inspected (in this case, the CO's surveillance test procedures), but instead a "representative number" of procedures is to be checked. Therefore, it is unclear what percentage of the STs in the control room were inspected during this audit.

In response to the concerns raised by the inspector the licensee performed a 100% audit of procedures in the station library and corrected all identified problems. Prior to the inspector's findings the licensee had developed plans to implement a better coordinated, more detailed audit program of station procedures. The licensee stated that this new audit plan will be implemented by April 1, 1991.

- The inspector reviewed the "PORC Position Interpretations of Technical Specifications" (PPTS) referenced in the Unit 2 reactor pressure vessel hydrostatic test procedure. Several discrepancies in the control of the PORC positions were noted. PPTS are controlled as procedures by Administrative Procedure A-2, and their generation is governed by A-4.1, "Administrative Procedure for the generation of Technical Specifications PORC Positions," Revision 0. The inspector found that the index to the PPTS contained reference to PPTS No. 49, which was not in the manual. PPTS No. 34 had attachments which were not labeled with number, revision, page number, and total pages to clearly identify the attachments as part of the position. During review of A-4.1 the inspector found that the controlled copy of A-4.1 did not have Exhibits A-4.1-1 and Exhibit A-4.1-2 attached, nor were the exhibits available in official hard copy files in the Document Control Group. The Nuclear Records library control copy had the exhibits attached. In response to these deficiencies the licensee reissued PPTS 49 and the exhibits to procedure A-4-1, and initiated an evaluation of the administrative errors noted in PPTS 34 and the reason for the missing A-4-1 exhibits.

Following the identification of the specific deficiencies discussed above, the inspector reviewed the Administrative Procedures (AP) governing the control of plant procedures and documents and interviewed licensee representatives in the Procedure Control Group, Nuclear Records, and Quality Control organizations. Licensee APs do not clearly define the responsibilities of the various participants in the procedure control process. The licensee utilizes Administrative Guidelines (AG) to provide more detailed instructions for the processing of procedure revisions and control mechanisms. Although the AGs address aspects of the process required by the licensee's Quality Assurance Plan they are not clearly linked by reference to the associated APs in all cases. Also AG-1 clearly states that they are guidelines and need not be followed. The inspector agreed that the APs need not contain all the detailed procedure processing instructions, but the process framework should be established in procedures which are required to be followed. In addition to correcting the specific problems previously discussed, the licensee committed to evaluate the APs for document control and to further define responsibilities, provide clear links to the AGs and to require adherence to the AGs where appropriate. The licensee has been implementing a series of actions to strengthen the document control program. This issue will remain unresolved pending review of the effectiveness of the licensee's actions, and assessment of a larger sample of document control program activities (UNR 91-08-01).

5.2 Control of Plant Procedure Changes

Administrative Procedure A-3, "Temporary Changes To Procedures," details the licensee's program for initiation, review, approval, distribution and cancellation of temporary changes (TC). For those procedures under Operations Department control procedure A-3, Section 7.10.3, requires that a copy of the TC be placed on the Control Room Procedures Cart, completion of the "Index of Temporarily Changed Procedures for Control Room Use," and "capture" of the associated procedure in the controlled procedure volumes using a red mylar cover. For other procedures, such as surveillance tests (ST) which are present in the control room, procedure A-3, Section 7.10.4, requires that the TC be logged in the "Temporary Change to Test Procedure Index," that the approved TC traveler and a copy of the revised procedure be place in the "Temporary Change to Test Procedure Log Book," and that the procedure be "captured" in the controlled procedure volumes. Adherence to the TC processing controls contained in A-3 is needed to ensure that the plant staff is made aware of any TC, and reviews these changes prior to procedure use.

On February 21, 1991, during a review of TCs to procedures available in the control room the inspector identified that System Operating (SO) Procedure SO2D-7.A-2 had an outstanding TC (91-262) against it but it was not "captured" in a red tinted mylar cover as required by A-3. Subsequently, the inspector reviewed the TC Log and audited TCs to the plant procedures located in the control room. In addition to the discrepancy mentioned above the inspector found the following problems:

- Unit 2 procedure GP-8.C was not captured although a TC to the procedure was in effect (91-250);
- Unit 2 procedure SO-18.7.A-2 was captured although the associated TC had been canceled (91-332);
- Unit 2 procedure AO-56E.2-2 was not listed in the TC log index although an outstanding TC was in place (91-321);
- Unit 2 procedures S0-24.2.A, SO-50C.5.A-2, and SO-50C.5.B-2 were listed with the wrong procedure numbers in the index (91-204, 91-156, 91-159);
- A canceled TC to Unit 2 procedure COL 3.1.A-2 was not cleared from the index (91-200);
- Unit 3 procedure SO-2D.7.A-2 was captured although the associated TC had been canceled (91-263), and

- Unit 2 procedures ST-1.6-2 and COL ST-25.2-1 were not listed in the ST log index or placed in the ST log although outstanding TCs were in place (91-500, 91-503).

Procedure A-3, Section 7.15.1, requires that the Operations Support Group (OSG) shall, on each normal work day, review the temporary changes processed on the previous day for correct implementation, remove and discard any temporary changes that have expired, and ensure that a stamped controlled copy of the current revision of the applicable procedure is in place for those TCs that are removed. However, the daily review performed by the OSG was apparently not effective in correcting the errors identified by the inspector.

The inspector informed the licensee that the above examples of failure to adhere to the provisions of procedure A-3 for the processing of TCs constitutes a violation of Technical Specification 6.8.1 (NV4 91-08-02).

The inspector noted that procedure A-3 states that the initiator of a procedure change is responsible for preparing and properly distributing the TC to all specified procedure locations. There are no restrictions or minimum qualifications required for the initiator. The traveler sheet that accompanies the TC has five specific verification sign-offs that the initiator has to complete. These sign-offs, however, do not include the steps performed in A-3, Sections 7.10.3 and 7.10.4.

Following identification of these discrepancies by the inspector, the licensee implemented immediate action to correct them and to ensure that any additional existing problems were identified and resolved. The licensee discussed the scope and conduct of the OSG audits with the responsible staff individuals and found that the method used was not adequate. Licensee management also found that the audits had been identifying ongoing problems with the incorporation and removal of TCs from control room procedures, but that the auditor's practice was to correct the problems without further investigation into the root causes for their occurrence. Following the inspectors review, the licensee took prompt action to strengthen the audit program and stated that a full review of procedure A-3 and its implementation would be conducted.

5.2 Temporary Plant Alteration Process Review

The inspector performed a review of selected temporary plant alterations (TPAs) to verify that adequate controls are in place and to verify proper implementation of station procedure A-42, "Control of Temporary Plant Alterations." The inspector selected a sample of three TPAs and assessed if the proper reviews and approvals had been obtained, 10 CFR 50.59 safety evaluations had been performed, and if documents were updated to reflect the installation of TPAs. In general, the inspector concluded that TPA control was adequate. No adverse effects on plant operations or safety were apparent as a result of the TPAs reviewed. However, several weaknesses with the TPA process were identified. Specifically, the number of active TPAs appeared excessive and many TPAs have been installed for a prolonged duration. At the time of this inspection there were over 80 active TPAs. Of these, 22 were greater than 1 year old. A-42 does not place a specific time limit on TPAs. It does state "It is intended that TPAs be minor in scope and of short duration." Additionally, the procedure calls for PORC to review for continued applicability all TPAs installed longer than 3 months. The inspectors review of the TPA log indicated that PORC reviews are being performed, but, most TPAs exceed the 3 month period before review.

Procedure A-42 requires that the Document Control Center distribute the designated marked-up temporary plant alteration (TPA) drawings and prints in accordance with A-6, "Drawing Control." Procedure A-6 requires that drawings and prints affected by a change document list all open change documents and a copy of the change document be attached to the affected controlled copies at each file location. The inspector determined that controlled drawings were not being updated to accurately reflect the installation of TPAs as required by procedures A-6 and A-42. The following examples were identified:

- Unit 2 TPA 02-12 isolated, cut and welded a plug into the low pressure sensing line to reactor core differential pressure transmitter DPT 2-2-3-65. Controlled drawing M-352 in the control room and the station library were not annotated to reflect this TPA. The TPA had been installed since March of 1990.

- Unit 3 TPA 62-4 installed jumpers and lifted a lead in panel 30C28 to clear a service platform jib crane loaded rod block signal. Drawing M-1-S-20, sheet 10 in the station library was not updated to reflect this TPA. The TPA has been installed since August of 1989.

- Unit 2 TPA 33-1 installed isolation valves and associated fittings on vents and drains of the ECCS and RCIC ESW room coolers. This TPA was removed from active status during this inspection period as a result of permanent modifications. However, during its period of installation and prior to its removal control room and library drawings were not updated. The TPA had been installed since April of 1990.

The inspector informed the licensee that failure to adhere to the provisions of procedure A-42 requiring update of drawings affected by TPAs is a violation of Technical Specification 6.8.1 (NV4 91-08-03).

Step 7.4.5 of procedure A-42 requires the PORC secretary to send a copy of the PORC approved TPA package and all original "marked-up" drawings for distribution to the Document Control Center (DCC). DCC does not annotate the designated drawings until after receiving confirmation that the TPA has been installed. Of the three TPAs reviewed by the inspector DCC had apparently not received notification that two had been installed. Drawings associated with the third TPA, even though received by DCC, were not updated. Following the inspector's review, the licensee initiated a 100% review of TPAs to ensure that affected drawings were annotated. A significant percentage of those examined were deficient. Additionally, an event investigation was initiated.

Following identification of the discrepancies described above, the inspector reviewed relevant Nuclear Quality Assurance (NQA) audits, and noted that they also identified deficiencies with TPA controls. NQA audit reports PA-89-27 and A000032 both recommended that a revision be issued to make the controlling procedure more "User Friendly." The first audit is now over 15 months old and the same revision is still in effect. Additionally, program deficiencies were noted during a third party review of the process in November of 1990. This review included drawing update problems similar to those discussed above. A licensee task force was established in November, 1990, to recommend methods to enhance the TPA process and that a revision to the procedure is under development. Although the drawing update problem had been identified and a review of overall procedure adequacy initiated, there apparently was no effective near-term corrective action implemented to resolve the specific weakness.

5.3 Review of Unit 2 Modifications

During the inspection period the inspectors reviewed a sample of ongoing plant modifications (MOD). This included detailed review of the technical and administrative adequacy of the modification package, assessment of modification work instructions issued for use in the field, the Maintenance Request Forms (MRF) used to implement the work, and observation of modification installation. The following modification packages were reviewed:

MOD 1498 Replace HPCI, RCIC & CS Testable Check Valves;

MOD 1548 MSIV Anti-Rotation Stem (AO-86B Only);

MOD 1891 Replace HPCI, RCIC, RHR, CS Flow Transmitters;

MOD 2069 Replace LPRM Cable With MI Cable;

MOD 5085 Turbine Stop Valve Closure and Control Valve Fast Closure Scram Bypass Setpoint Revision, and

R441 CRD Support Upgrade.

In all cases the inspectors found that work in progress was well controlled, and no technical deficiencies with the modifications were identified.

6. SURVEILLANCE TESTING OBSERVATIONS (61701, 61726, 71707)

6.1 Routine Observation

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

ST 6.18-2	"IST Valve Exercise (for MO-2-10-17)," on February 14,
SI-2M-60F-83MD	"Scram Response Time Testing," on February 20,
ST 13.18-2	"Standby Liquid Relief Valve, Injection and Recirculation Testing," on February 26,
ST 1.6-2	"RHR Logic A System Functional Test," on March 13,
SP-1330	"Bumping 2A or 2B Recirculation Pump for Rotational Verification Check," on March 13,
ST 12.10	"Core Post Alteration Verification," on March 6-7,
ST 6.5.1	"HPCI Auxiliary Oil Pump Surveillance," on February 26,
ST 8.7	"Emergency Transformer Daily Surveillance," on March 11,

No concerns except as noted below were identified by the inspectors.

During a Unit 2 tour the inspector noted that the emergency load center transformer E-224 temperature monitor had failed downscale. An equipment trouble tag and MRF had been initiated. The gas temperature monitors hot spot temperature, a parameter associated with the potential for coil insulation damage. The associated MRF was assigned a level 4 priority, to be accomplished during the next outage. Temperature, gas pressure and load are monitored daily using ST 8.7, "Emergency Transformer Daily Surveillance," Revision 7. This surveillance assures that load limits will not be exceeded. The inspector reviewed four previously completed STs for completeness and to determine how the failed temperature monitor was being tracked. The auxiliary operators had noted on the data sheet that the failed temperature probe had an associated MRF. However, there were inconsistencies in declaring the temperature limits unsatisfactory. The acceptable range is less than 200 Celsius. Since a MRF had been initiated some operators declared the surveillance satisfactory. Two out of four STs were signed-off as unsatisfactory. Apparently there is not a clearly defined policy governing disposition of STs with failed equipment parameters if the parameter is not TS, ISI, or code related. In this case the parameter was being monitored in response to an NRC commitment. The licensee, in response to these concerns, is preparing changes to the Operations Management Manual which will provide clear guidance for declaring acceptance criteria satisfied and how to handle inoperable monitoring equipment.

6.2 Unit 2 Reactor Pressure Vessel Hydrostatic Test Review

The inspector reviewed the hydrostatic test surveillance procedure ST 25.2, "RPV Primary System (Class 1) Hydrostatic Test (Unit 2 Only)," Revision 1, with the associated Temporary Change Forms for adequacy prior to the performance. In addition, the inspector evaluated licensee preparations for the test, and test coordination and conduct. The evolution was effectively coordinated and well conducted. Prior to performance of the test the inspector noted that the procedure did not specifically address the auto-high pressure scram signal that would be received at 1055 pounds per square inch gauge (psig). The licensee changed the procedure prior to pressurizing the vessel to address the auto-scram. The inspector had no further questions.

7. MAINTENANCE ACTIVITY OBSERVATIONS (62703)

7.1 Routine Observation

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.
The following maintenance activities were observed and/or reviewed:

MRF 9004379	IRM G Power Supply Cable Replacement, on February 20;
MRF 9100224	IRM C Power Supply Module Replacement, on February 20;
MRF 9062071	Remove the Cattle Shute, on March 5;
MRF 9100842	Rework HPCI Pump Cooling Water Header Broken Fitting, on March 6;
MRF 9100695	Change HPCI Oil, on March 6;
MRF 9085586	CRD Piping Support Repair, on February 26, and
ETT 47688	Emergency Load Center Transformer Failed Temperature Monitor, on March 11.

No concerns were identified by the inspectors.

7.2 Unit 3 High Pressure Coolant Injection System Outage Observation

The inspector reviewed portions of the Unit 3 HPCI scheduled outage conducted the week of March 4, 1991. The maintenance was planned as part of the licensee's rolling system outage schedule. This approach allows maintenance activities associated with a certain system to be scheduled and performed during a specified time frame. During the HPCI outage the inspector examined work packages and observed activities of maintenance in progress.

The inspector noted good coordination between the working groups. The HP technician covering the job held a pre-job brief, performed a pre-job walkdown and also expanded the contaminated boundary to better accommodate the work activities. Engineering personnel were observed at the job site and were cognizant of activities. Management oversight was also evident.

8. RADIOLOGICAL CONTROLS (71707, 83750)

During the report period, the inspector examined work in progress on 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.

9. 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.

10. PREVIOUS INSPECTION ITEM UPDATE (92701, 92702, 92720, 92703)

(Closed) UNR 89-82-001, Review for Acceptability PORC Chairman Completing Plant Manager Approval of PORC Meeting Items.

It was noted that in many cases the PORC Chairman had signed the Plant Manager's approval line on Exhibit AG-12-4, "PORC Review/Approval Form," to Administrative Guideline AG-12, "PORC Administration." Given the advisory function of the PORC to the Plant Manager on safety-related matters the inspector questioned the appropriateness of the PORC Chairman's completion of the Plant Manager's approval line.

The Plant Manager issued a letter on March 15, 1990, which clearly stated the designated alternates to approve the PORC Review and Approval form and when the designated alternates could exercise that authority. The inspector had no further questions and this item is closed.

(Closed) UNR 90-25-003, Review of the Reason Why the Revision Mechanism for ST 8.7 was Faulty.

During review of ST 8.7, Revision 7, "Emergency Transformer Daily Surveillance," an inspector noted that on the data sheet the temperature acceptance criteria for those transformers with skin temperature monitors should have been 100° Celsius (C) rather than 200°C which is the appropriate limit for hot spot temperatures. The inspector noted that revision 6 of the procedure had the correct criteria for skin temperature. Revision 6 was revised for matters other than the temperature criterion and approved by PORC with the correct temperature criterion on the marked-up copy. However, when revision 7 was published by the Nuclear Records Group the 100°C temperature criteria for each of the skin temperatures monitored had reverted to 200°C. The resulting error was minor. However, if a general underlying weakness exists in the procedure revision process, it could cause more serious problems if left uncorrected.

The licensee's investigation revealed that several barriers to prevent errors in the procedure revision were breached resulting in the publishing of the deficient procedure. Electrical System Engineering (ESE), the group responsible for the revision obtained the controlled computer word processing file of the procedure from Nuclear Records and incorporated the PORC reviewed changes. However, when the disk containing the revised procedure was transmitted via company mail to the Nuclear Records Group, it was lost. When the revised file could not be found the Nuclear Records Group discovered that they had lost the controlled computer file copy of the procedure. They retyped the revised procedure, but requested that ESE provide the data sheets since they were generated using graphics software that the Nuclear Records Group did not have. ESE apparently provided a copy of revision 5 data sheets in the graphics software which had all temperature criteria of 200°C, rather than revision 6 data sheets, which were correct. The proofing of the revised procedure by ESE and the Nuclear Records Group concentrated on the changes in the revision rather than the complete procedure, so the changes in the data sheets were overlooked. To prevent recurrence the Nuclear Records Group will:

- Change Procedure AG-14 to require all responsible groups who revise procedures to obtain the controlled copy of the procedure from the Document Control Group throughout the activity, even to replace lost copies;

- Require word-for-word proofreading by the originating and Document Control Groups; and

- Revise proofreading guidelines and training in proofreading.

Based on the corrective actions the inspector had no further questions.

(Closed) UNR 89-26-001, Review of the Backlog of Operations Incident Reports.

An inspector reviewed the Operations Incident Investigation system and noted that a large backlog of about 90 incident reports existed. These reports had received little evaluation and exhibited a 2 to 3-month delay from the date of occurrence until a meaningful assessment was performed. As a result of this review, the licensee allocated additional resources to assess, on an individual basis, and disposition the noted backlog.

The inspector reviewed a sample of the dispositioned incident reports. It should be noted that the individual event assessments were performed in accordance with the investigation system in place at the time of issuance. That system was replaced by the present Nuclear Group Administrative Procedure (NGAP) number NA-02A002, "Investigation of In-house Events." The inspector found that the reviews were adequate, but not of the same quality or depth as the reviews performed under the present program. All event information and corrective actions have been entered into the Plant Information Management System (PIMS) and the Incident Review Database where it can be tracked and trended. The inspector had no further questions and this item is closed.

11. MANAGEMENT MEETINGS (71707)

The Resident Inspectors provided a verbal summary of preliminary findings to the Peach Bottom Station Plant Manager at the conclusion of the inspection. During the inspection, the Resident Inspectors verbally notified licensee management concerning preliminary findings. No written inspection material was provided to the licensee during the inspection. This report does not contain proprietary information. The inspectors also attended the entrance or exit interviews for the following inspections during the report period:

Dates	Subject	Report No.	Inspector
2/18/91	Inservice Inspection	91-09	McBrearty
3/4/91	Security Program	91-10	Limroth
3/18/91	Effluent Controls	91-12	Jang

ATTACHMENT I

Facility and Unit Status

Unit 2

Unit 2 remained in a refueling outage during the entire period.

February 12	Primary containment isolation system and standby gas treatment system initiation due to an electrical ground.
February 20	Inadvertent reactor scram due to inadequate blocking.
February 21	Loss of shutdown cooling due to inadequate blocking.

Unit 3

February 12	Reactor power at 100%.
February 15	Reactor power reduced to 65% for control rod pattern adjustment.
February 18	Reactor power returned to 100%.
February 24	HPCI inoperable due to lack of tappet assembly spring force in the mechanical overspeed trip device. Return to service in two hours after spring tension readjusted.
March 4	Reactor power briefly reduced to 85% when the circulating water inner screens became clogged with minnows during reduced pond level. This resulted in loss of suction to a circulation pump. Power was reduced when the pump was removed from service so that the screens could be cleaned.
March 5	Reactor power returned to 100%.
March 15	Reactor power reduced to 76% for control rod pattern adjustment and maintenance on "A" feedwater pump.
March 16-18	Reactor power returned to 100%, and remained at full power to the end of the period.

ATTACHMENT II

List of Attendees - February 25, 1991
Meeting on Peach Bottom Fuel Handling Events

Name	Title/Organization
NRC Participants:	
T. Martin	Regional Administrator
C. Hehl	Director, Division of Reactor Projects (DRP)
J. Wiggins	Deputy Director, DRP
L. Bettenhausen	Chief, Operations Branch, Division of Reactor Safety (DRS)
W. Lanning	Deputy Director, DRS
J. Durr	Chief, Engineering Branch, DRS
L. Doerflein	Acting Chief, Projects Branch 2, DRP
R. Conte	Chief, Boiling Water Reactor Section, DRS
P. Eapen	Chief, Special Test Programs Section, DRS
J. Lyash	Senior Resident Inspector, Peach Bottom
G. Suh	Project Manager, Office of Nuclear Reactor Regulation
J. Trapp	Senior Reactor Engineer, DRS
J. Williams	Senior Operations Engineer, DRS
D. Screnci	Field Public Affairs Officer
Philadelphia Electric Company Participants:	
D. Smith	Senior Vice President, Nuclear
D. Helwig	Vice President, Nuclear Engineering and Services
J. Franz	Plant Manager, Peach Bottom Atomic Power Station (PBAPS)
W. MacFarland	Manager, Nuclear Maintenance Division, PBAPS
W. Texter	Reactor Servicing Support
T. Niessen	Operations Superintendent, PBAPS
G. Beck	Licensing Manager
P. Berry	Licensed Senior Operator
G. Storey	Plant Support Branch Head

ATTACHMENT III

2/25/91

AGENDA
NUCLEAR REGULATORY COMMISSION
Peach Bottom Atomic Power Station
Management Meeting

I. INTRODUCTION

II. DISCUSSION OF FUEL POOL

III. REACTOR LOW TEMPERATURE

IV. SUMMARY

AGENDA

2/25/91

NUCLEAR REGULATORY COMMISSION

Peach Bottom Atomic Power Station
Management Meeting

I. Introduction

II. Discussion of Fuel Pool/Core Reload

- A. Walk-through Normal Reload Activity Cycle
- B. Discussion of Four "Mispicks" During Reload
- C. Cessation of Core Reload
- D. Significance of Misplaced Bundles
- E. Conclusions

III. Reactor Low Temperature

- A. Introduction
- B. Identification
- C. Cause
- D. Significance
- E. Corrective Action
- F. Closure on Reactor Low Temperature

IV. Summary