U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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Report Nos.	98-11 98-11
Docket Nos.	50-277 50-278 72-1027
Licensee:	PECO Energy Company Correspondence Control Desk P.O. Box 195 Wayne, PA 19087-0195
Facility:	Peach Bottom Atomic Power Station Units 2 and 3
Inspection Period:	November 10, 1998 through January 4, 1999
Inspectors:	A. McMurtray, Senior Resident Inspector M. Buckley, Resident Inspector B. Welling, Resident Inspector S. Dennis, Operations Engineer J. Carrasco, Reactor Engineer M. Thadani, NRR Project Manager
Approved by:	Curtis J. Cowgill, Chief Projects Branch 4 Division of Reactor Projects

EXECUTIVE SUMMARY

Peach Bottom Atomic Power Station
NRC Inspection Report 50-277/98-11, 50-278/98-11

This inspection report included aspects of licensee operations; surveillances and maintenance; engineering and technical support; and plant support areas.

Operations:

- The plant operators performed well during the Unit 3 shutdown and startup for the instrument nitrogen leak repair and the reduction in power for replacement of the main turbine lubricating oil baffler valve and pump. Procedures were properly followed and communications and shift oversight were effective and professional. (Section O1.1)

- Control room operators responded as expected to an electrical transient caused by a loss of the 2 emergency auxiliary transformer. Licensee personnel took timely and effective corrective actions to repair damaged terminal components, address the generic concerns, and restore the emergency transformer to operation. (Section O2.1)

- On November 30, 1998, inadequacies in a breaker manipulation procedure led to an unexpected loss of one off-site power source and several emergency safety feature actuations. Plant operators performed well during this event while challenged by the loss of control rod drive pumps and reactor water cleanup system isolation on both units and a recombiner isolation and power reduction on Unit 3. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy. (Section O3.1)

- Three licensed operators failed to successfully complete requalification training during the licensee requalification training program which ran from April 1994 through March 1996. Additionally, as a result of the failure to make up missed training until April 1998, one operator license renewal application, was submitted to the NRC with inaccurate information. The application incorrectly certified that the applicant had met the requirements of the approved requalification program during the effective term of the then current license. This was a violation of 10 CFR 55.57(a)(4) and 10 CFR 55.9. Corrective actions for the missed training and inaccurate application were adequate. (Section O5.1)

- Procedure adherence in the performance of winterizing procedures was improved. However, weaknesses in station winterizing procedures and personnel attentiveness to heating/ventilating system equipment led to a number of minor, cold weather-related equipment problems. (Section O8.1)

Executive Summary (cont'd)

Maintenance:

- Station personnel discovered that a Technical Specification Surveillance Requirement for average power range monitor channel calibration was not met during Unit 2 power ascension due to an inaccurate heat balance calculation. The heat balance calculation inaccuracy was due to substitute values installed by instrument and control and engineering personnel during flow transmitter calibrations. The calculated heat balance values were always conservative from a safety perspective and station personnel took adequate and reasonable corrective actions for this event. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy. (Section M4.1)

Engineering:

- Three reactor core thermal management problems occurred during this inspection period related to the 3D MONICORE program. Two problems were related to configuration management of input data to the program and one was related to unexpected program results. The licensee investigated these problems and took appropriate initial actions and developed appropriate corrective actions. No thermal limits were exceeded as a result of these problems. (Section E4.1)

Plant Support:

- Radiation protection personnel provided very good oversight of control rod blade component removal from the Unit 3 spent fuel pool and replacement of a Unit 2 traversing incore probe. Good awareness for As-Low-As-Reasonably-Achievable (ALARA) by personnel involved with this work, and effective planning and monitoring by radiation protection personnel resulted in low doses for these activities. (Section R4.1)

- The licensee had appropriately maintained the barriers and isolation zones around the protected area. Security equipment in the Central Alarm Station and Secondary Alarm Station areas were functioning properly. Activities in these areas would not have interfered with the execution of the detection, assessment or response functions. (Section S2.1)

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Report Details

Summary of Plant Status

PECO operated both units safely over the period of this report.

Unit 2 began this inspection period at 100% power. During the early morning of December 19, 1998, unit load was reduced to 60% to repair a leak on the B3 feedwater heater extraction steam line. Unit load returned to 100% power during the afternoon of December 19 following this repair. On January 2, 1999, unit load was reduced to 65% to allow repairs to the main turbine #3 control valve. The unit was returned to 100% power on January 3.

Unit 3 began this inspection period at 100% power. The unit was manually scrammed on November 27, 1998 to repair an instrument nitrogen supply line. The unit was returned to 100% power on December 1. On December 3, the main turbine was taken off line to replace the main turbine lube oil baffle booster pump and valve. The reactor remained critical while this work was performed. The unit was returned to 100% power on December 11. Unit power remained at 100% for the rest of the period.

I. Operations

O1 Conduct of Operations[1]

O1.1 General Comments

a. Inspection Scope (71707)

The inspectors observed portions of the Unit 3 shutdown and startup for instrument nitrogen leak repair and the reduction in power to allow tripping the main turbine to facilitate replacement of the main turbine lubricating oil baffler valve and pump. The inspectors also verified that heatup and cooldown rates were maintained within requirements during these maneuvers .

b. Observations and Findings

On November 27, 1998, operators shut down Unit 3 to repair a nitrogen leak on an air operated valve inside the drywell. The unit was restarted on November 28 following repairs. On December 3, 1998, operators noted abnormal vibration and noise coming from the main turbine lube oil reservoir. Subsequent troubleshooting indicated that the main turbine baffle booster pump was performing unsatisfactorily.

The operators commenced a well controlled load reduction to the allow removal of the main turbine from service. Unit 3 was maintained critical on the bypass valves until the main turbine lube oil baffle pump and valve were replaced, tested, and returned to

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[1] Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

service. The return to full power was well controlled, in accordance with procedures, and the unit operated well within acceptable operating parameters.

Plant operators performed well during these maneuvers and appropriately followed site procedures. Professional and effective communications and shift oversight were also observed. Reactor coolant heatup and cooldown rates were well controlled within requirements.

c. Conclusions

The plant operators performed well during the Unit 3 shutdown and startup for the instrument nitrogen leak repair and the reduction in power for replacement of the main turbine lubricating oil baffler valve and pump. Procedures were properly followed and communications and shift oversight were effective and professional.

O2 Operational Status of Facilities and Equipment

O2.1 Inoperable Off-site Power Source and Station Blackout Line Due to the Failure of the 2 Emergency Auxiliary (EA) Transformer

a. Inspection Scope (71707)

The inspectors observed the actions taken by Peach Bottom Site personnel in response to the trip of the 2 SU-E Breaker due to failure of the 2 emergency auxiliary (EA) transformer. The inspectors also reviewed the associated electrical schematics related to this event.

b. Observations and Findings

On December 27, 1998, with both units at 100% power, the 2 SU-E breaker tripped open on high current. The applicable (E312, E323, E332, E343) 4KV emergency bus feeder breakers fast transferred to the 3SU-E feed automatically. The breaker trip resulted in isolation of the reactor water cleanup systems and loss of the 'A' control rod drive (CRD) pumps on both units, and start of the control room emergency ventilation (CREV) system. Control room operators maintained the plant in a stable condition during this transient, with no indication of changes in reactor water level, pressure, or power. The licensee submitted a 10 CFR 50.72 event notification due to the engineered safety feature (ESF) actuations.

The inspectors independently examined the 2 EA transformer and observed that the cable connection panel sides had bulged out and the insulators for the cable connections were significantly damaged. The licensee's investigation revealed that the 'B' phase support bushings on the 2 EA transformer 4KV side had failed, causing a short circuit and overpressure event in the terminal panel. The overcurrent 251B and 251C relays on the 2SU-E breaker had tripped in response to overcurrent. There was no other significant damage to the transformer or 4 kV bus cables. Maintenance technicians repaired the terminal connections to the transformer and replaced the damaged insulators.

The licensee determined that stress on the insulator bushings due to mechanical loading of the cables into the transformer had created fine cracks that allowed conditions for a short circuit. The licensee took action to eliminate the condition and evaluated the possibility for these conditions on other site transformers. The licensee stated that recent preventative maintenance and inspection of the other transformers should provide adequate assurance that their insulators are in satisfactory condition.

During a review of electrical schematics and procedures related to station blackout (SBO), the inspectors noted that station blackout procedures did not address energizing the emergency buses with the SBO line through the 3 EA transformer if the 2 EA transformer was not operable. The inspectors noted that the SBO rule did not require having the capability to energize the emergency buses with the SBO line through the 3 EA transformer, but PECO indicated that they would consider developing a procedure to provide this flexibility.

c. Conclusions

Control room operators responded as expected to an electrical transient caused by a loss of the 2 emergency auxiliary transformer. Licensee personnel took timely and effective corrective actions to repair damaged terminal components, address the generic concerns, and restore the emergency transformer to operation.

O3 Operations Procedures and Documentation

O3.1 Loss of Off-Site Power Source and 2SU Bus Trip Due to Electrical Bus Switching During Planned Breaker Maintenance and (Closed) Licensee Event Report (LER) 50-277/2-98-008

a. Inspection Scope (71707)

The inspectors reviewed the plant and operator response to the trip of the SU25 breaker during transfer of the No. 2 startup feed bus from 2SU to 343SU. This review included the operating procedures and the licensee's evaluation of the cause of the event.

b. Observations and Findings

On November 30, 1998, operations personnel established a breaker lineup which caused the offsite SU-25 breaker to unexpectedly trip during realignment of the 13kV electrical system. This de-energized the 2 Start-up and emergency auxiliary transformers resulting in six 4KV emergency buses fast transferring to the 3 Start-up and emergency auxiliary buses.

During the electrical switching activities, system operating (SO) procedure, SO 53.6.B, Revision 27, "Auxiliary Electrical System Transfer Operations" directed the transfer of the 2SU-B bus feeder from 2SU bus to 343SU bus. Due to procedure inadequacies, the 2SU bus was unexpectedly de-energized while transferring the 2SU bus feed. This initiated an electrical transient and resulted in the loss of control rod drive (CRD) pumps, reactor water cleanup system (RWCU) isolations, and engineered safety feature (ESF) actuations on both units, control room emergency ventilation (CREV) start, and a recombiner isolation on Unit 3. Control room operators reduced reactor power on Unit 3 due to the recombiner isolation.

The licensee determined that system modifications in 1992 were not adequately incorporated into the existing operating procedures. Following this event, operations personnel re-preformed these procedures in the simulator and the equipment performed as it did during the transient.

Due to the ESF actuations, the licensee made an event notification to the NRC in accordance with 10 CFR 50.72. The inspectors completed an on-site review of the licensee's LER submittal, and had no concerns with the report or corrective actions presented.

Technical specifications 5.4.1 requires, in part, that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Appendix A. Regulatory Guide 1.33, Appendix A, includes procedures covering energizing and changing modes of operation for on and off site electrical systems. Contrary to the above, as of November 30, 1998, PECO did not properly establish written procedures for changing electrical system modes. Specifically, procedures SO 53.6.B, Revision 27, "Auxiliary Electrical System Transfer Operations and SO 53.7.T, Revision 0, "Startup Bus Outage" were inadequate for controlling electrical system mode changes.

The inspectors concluded that the operators took appropriate actions during this event and that the licensee's corrective actions for this event were reasonable and effective. Therefore, this non-repetitive, licensee-identified and corrected violation and is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-277/98-11-01)**

c. Conclusions

On November 30, 1998, inadequacies in a breaker manipulation procedure led to an unexpected loss of one off-site power source and several emergency safety feature actuations. Plant operators performed well during this event while challenged by the loss of control rod drive pumps and reactor water cleanup system isolation on both units and a recombiner isolation and power reduction on Unit 3. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy.

O3.2 Unexpected Unit 3 Rod Worth Minimizer Rod Block During Control Rod Drift Alarm Test

a. Inspection Scope (71707)

During performance of a routine test (RT) of the control rod drift alarm, the Unit 3 reactor operator received an unexpected rod worth minimizer (RWM) rod block in both the insert and withdraw directions. The inspectors discussed this issue with operations and reactor engineering personnel and reviewed applicable documentation.

b. Observations and Findings

On December 6, 1998, the Unit 3 reactor operator was performing RT-O-003-930-3, Revision 5, "Control Rod Drift Alarm Test" with reactor power below the low power setpoint. Prior to performing the test, an RWM insert error was present because rod 14-15 was past its insert limit due to a bad position indicator. When rod 02-23 was moved inward to position 46 during the performance of RT-O-003-930-3, a second insert error occurred and an RWM insert rod block occurred. The RWM latched into the rod group containing rod 14-15 at its current position, sensed a withdraw error, and an RWM withdraw block also occurred. In response, operations personnel entered Abnormal Operating (AO) procedure 62A.1-3, Revision 14, "Rod Worth Minimizer System Manual Bypass" to bypass the RWM and restore rod 02-23 to its original position. Rod 02-23 was returned to position 48, the RWM was reinitialized, and AO 62A.1-3 was exited.

The licensee initiated Performance Enhancement Program (PEP) report I0009245 for this event. During their investigation for this PEP, the licensee determined that RT-O-003-930-3 did not prevent performance of this RT below the RWM low power setpoint. Similar procedures, such as the control rod exercise surveillance test, were not allowed to be performed below the low power setpoint.

The inspectors determined based on interviews, that operations personnel involved with this issue did not fully understand the logic for the RWM rod blocks. Although the Unit 3 reactor operator expected the insert rod block when he moved rod 02-23 to position 46, he did not expect the withdraw block. Because of this block, he had to manually bypass the RWM to restore rod 02-23 to the original position to complete the alarm test.

The inspectors noted that corrective actions for PEP I0009245 included making changes to RT-O-003-930-3 to ensure that reactor power was greater than the RWM low power setpoint prior to performing the test. Corrective actions also included training for licensed operators and reactor engineers that emphasized the latching criteria used by the RWM. The inspectors reviewed these corrective actions and had no concerns.

c. Conclusions

Unexpected rod worth minimizer insert and withdraw rod blocks occurred when the Unit 3 reactor operator inserted a control rod one notch during a control rod drift alarm test. Overall, corrective actions for this issue were comprehensive and addressed the identified causes.

O5 Operator Training and Qualification

O5.1 Licensed Operator Requalification Training Program and (Closed) Unresolved Item (URI) 50-277(278)/98-04-01 Failure of Certain Licensed Operators to Complete Requalification Training

a. Inspection Scope (71001)

The inspectors followed up on unresolved item (URI) 50-277(278)/98-04-01 which described the failure of four licensed operators to make up missed training following the training period of April 1994 to March 1996. Additionally, the inspectors reviewed an issue concerning the accuracy of operator license renewal applications (NRC Form 398) submitted to the NRC during the past 4 years. An in-office and on-site review of the following documents was performed:

- Past and current training attendance records
- Previous and current revisions of the Peach Bottom (PB) licensed operator requalification training course plan (POC-2.4 Revs.7&8)
- Licensee corrective action documents; PEP I0008441, I0008445, I0004734, I0007366, and AR-A1168753
- Licensee letters further explaining the issues, dated April 16,1998 and September 18, 1998
- Operator license renewals (NRC Form 398) submitted from 1994 through 1998

Also reviewed was the NRC Office of Investigation Report No. 1-98-020 (synopsis documented in Attachment 2).

b. Observations and Findings

The inspectors found upon review of the documents and an NRC Office of Investigations (OI) report that four individuals had not completed the 24 month licensed operator requalification training (LORT) cycle which was conducted from April 1994 through March 1996. The inspector noted that one of the individuals, per Peach Bottom procedure POC-2.4-Rev.7, was not required to attend requalification training due to being enrolled during that period in a Senior Reactor Operator License Upgrade class which covered the same subject areas. However, the inspector found that during that cycle, the other three individuals missed training in subject areas which included technical specifications, normal and emergency operating procedures, and plant systems. Further, the operators had not made up the training, in some cases, until April 1998. Therefore, the three operators had not successfully completed the 24-month LORT cycle from April 1994 through March 1996 which is contrary to 10 CFR 55.59a(1).

Additionally, as a result of the missed training, the inspectors found that one of the individuals, had not successfully completed the requalification program and had submitted a license renewal application (NRC Form 398), signed by the operator and authorized representatives of the facility. The application certified that the individual met the approved requalification program as required by 10 CFR 50.54(I-1) and 10 CFR

55.59(c). An approved program constitutes, in part, attendance at all training or completion of make up training. The signed application, certifying program completion, was submitted on October 4, 1996 and the inspector's review of licensee records found that make up training for numerous missed training sessions was not completed until April 1998. Therefore, the program was completed in April 1998 and not on October 4,1996, as certified on the applicants NRC Form 398. Accordingly, the signed application was inaccurate which is contrary to 10 CFR 55.57(a)4 and 55.9.

The inspectors reviewed licensee root cause analysis and corrective actions as noted below.

Missed Requalification Training

The licensee determined that the root cause of the missed requalification training was due to inadequate guidance and subsequent incorrect interpretation of attendance requirements in the licensed operator course plan, POC2.4 Rev.7. The course plan stated at step 6.1.2.3.1. that "the individual shall make-up the missed training by an alternative method as determined by the Manager-Operations Training." The "alternative method" permitted by certain members of the operations training department, in these cases, was successfully passing the annual requalification exam in lieu of training attendance. The licensee has determined this was the wrong interpretation of 10 CFR 55.59 requirements.

The inspectors verified the associated corrective actions are complete as noted below.

- Memorandum to all licensed operators dated June 1, 1998, from the Senior Manager-Operations, stating training attendance expectations and requirements per 10 CFR 55.59.

- Revision of the course plan, POC2.4 Rev.8 section 7.5.2.2, which specifically describes attendance requirements and the requirement to make up missed training within 12 weeks (the end of the following cycle) or be removed from license duties until the training is complete.

- Revision of the course plan, POC2.4 Rev.8 section 7.5.2.3, which states that all training deficiencies must be complete prior to taking any part of the annual or biennial exams.

- Revision of the course plan, POC2.4 Rev.8 section 7.5.2.2, which requires notification of the Senior Manager-Operations for failure to make up training within the prescribed time limit.

- Revision of training attendance sign-in sheets with at least two levels of supervisory review.

Additionally, the inspectors reviewed attendance records for the previous six months and found them to be up to date, attendance at a very high level, and make up sessions completed as required. Also noted, were ongoing management meetings with all operators during the current requalification cycle, reemphasizing training expectations.

The inspectors concluded that the root cause for the missed training was programmatic and not willful on the part of individuals, in that the program was not specific regarding the requirements for determining successful completion of training. Additionally, the root cause was adequately documented and the associated corrective actions were comprehensive, fully implemented, and acceptable overall.

Inaccurate NRC Form 398

The licensee determined that the root cause of the inaccurate NRC Form 398 was due to the lack of a single point of ownership in the license application submittal process as described in procedure A-C-10 - Operator Licenses (PEP-I0007366 and AR-A1168753). The procedure described the correct process for application completion and submittal but delineated responsibility among various licensee personnel for completion. No single point contact was apparent in A-C-10 to assure accurate completion prior to submittal. The recommended corrective action by the licensee was a revision of procedure A-C-10 to assure that the submittal process is clarified with responsibility clearly identified.

The inspectors determined that root cause determination for the inaccurate 398 form was reasonably thorough. The inspectors also determined that one corrective action, revision of procedure A-C-10, which described the process for submission of operator license renewal applications, will be completed in February 1999 according to licensee AR A1168753.

The inspectors concluded that the inadequate program requirements to ensure attendance at LORT and avoid excessive delays in make up training most likely caused the inaccurate NRC Form 398 to be submitted. Accordingly, the actions contrary to the various requirements noted above are collectively viewed as one violation. **(VIO 50-277(278)/98-11-02)**

No further concerns were identified during the reviews of the issues raised by URI 50-277(278)/98-04-01.

c. Conclusions

Three licensed operators failed to successfully complete requalification training during the licensee requalification training program which ran from April 1994 through March 1996. Additionally, as a result of the failure to make up missed training until April 1998, one operator license renewal application (NRC Form 398), was submitted to the NRC with inaccurate information. The application incorrectly certified that the applicant had met the requirements of the approved requalification program during the effective term of the then current license. This was a violation of 10 CFR 55.57(a)(4) and 10 CFR 55.9. Corrective actions for the missed training and inaccurate NRC Form 398 were adequate.

O8 Miscellaneous Operations Issues

O8.1 (Closed) Violation (VIO) 50-277(278)/97-08-01 Cold Weather Preparations Procedural Non-Compliance

a. Inspection Scope (71707, 92901)

NRC Inspection Report 50-277(278)/97-08 discussed a number of discrepancies associated with the documentation and performance of winterizing procedures. In response to the Notice of Violation, dated March 25, 1998, PECO attributed the cause of the violation to poor procedure compliance. The inspectors reviewed the corrective actions for the procedure compliance deficiencies, as implemented in the performance of routine tests RT-O-040-620-2, Revision 6, "Outbuilding Heating, Ventilation and Air Conditioning (HVAC) and Outer Screen Inspection for Winter Operation," and RT-O-040-630-2, Revision 5, "Winterizing Procedure," in November 1998.

b. Observations and Findings

The inspectors noted that the completed routine test procedures were well-documented, and maintenance action requests were initiated for all identified equipment deficiencies. A spot-check of several components revealed no discrepancies. The inspectors concluded that this violation was closed.

Despite these improvements in procedure compliance, several minor equipment problems occurred during a period of cold weather in early January 1999, including:

- A frozen instrument line for the 3A circulating water pump. Operators found that the doors to the pump structure did not fully close and had gaps in the weatherstripping. Although the affected instrument line provided only control room indication, an adjacent instrument line provided pump trip functions. If frozen, this could lead to a pump trip and subsequent plant transient.
- Failed circulating water pump structure roof exhauster dampers, which were not shutting as required when the associated fan was off.
- Some non-functional reactor building area heaters, discovered after receiving a standby liquid control system tank/pipe low temperature alarm.
- A non-functional heating/cooling fan in the E4 emergency diesel generator (EDG) room.
- E4 EDG jacket water low temperature alarm. EDG operability was not affected.

The inspectors brought these issues to the attention of operations personnel, who reviewed the adequacy of the winterizing procedures as well as their implementation. Operations management determined that the winterizing procedures needed some minor improvements and that personnel needed to be more attentive to heating/ventilating system equipment and to components potentially affected by cold weather.

c. Conclusions

Procedure adherence in the performance of winterizing procedures was improved. However, weaknesses in station winterizing procedures and personnel attentiveness to heating/ventilating system equipment contributed to some minor, cold weather-related equipment problems.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Observations

NRC Inspection Procedures 62707 and 61726 were used in the inspection of plant maintenance and surveillance activities. The inspectors observed and reviewed selected portions of the following maintenance and test activities:

Maintenance Observations:	Observed On:
Replace Relay & Verify Operation in RPS, RO 264628	December 14, 1998
Replace Relay & Verify Operation in RPS, RO 264066	December 14, 1998
Replace Relay & Verify Operation in RPS, RO 264033	December 14, 1998
Replace Relay & Verify Operation in RPS, RO 264035	December 14, 1998
Investigate & Doble Test Transformer, CO 185854	December 30, 1998

Surveillance Observations:		Observed On:
RT-O-007-550-2	Containment Gross Leak Rate Detection	November 30, 1998
SI2M-7J-872-BICQ	Calibration Check of CAD/CAC Oxygen and Hydrogen Analyzers and Recorder	December 3, 1998
ST-O-60A-210-3	APRM System Calibration During Two Loop Operation	December 8, 1998
SI2A-2-RPS-A1FQ	Functional Test of RPS "A" Card File	December 14, 1998
ST-O-052-700-2	E1 EDG 24 Hour Endurance Test	December 15, 1998
RT-O-052-202-2	E2 Diesel Generator Load Run	December 31, 1998

The work and testing performed during these activities was professional and thorough. Technicians were experienced and knowledgeable of their assigned tasks. The work and testing procedures were present at the job site and actively used by the technicians and operators for activities observed. Good pre-job briefs were observed prior to the performance of the surveillances observed. System managers were usually present during surveillance tests and provided good technical oversight.

M4 Maintenance Staff Knowledge and Performance

M4.1 Failure to Meet Technical Specification (TS) Surveillance Requirements for the Absolute Difference in the Average Power Range Monitor (APRM) Channels and the Calculated Reactor Power Due to Substitute Feedwater Flow Temperature Correction Factors in the Heat Balance Calculation (Closed) LER 50-277/2-98-007

a. Inspection Scope (62707 & 37551)

On November 16, 1998, station personnel discovered that a technical specification surveillance requirement involving calibration of the APRM channels had not been met during Unit 2 power ascension due to an inaccurate heat balance calculation. The heat balance calculation inaccuracy was due to substitute values installed for feedwater flow temperature correction factors during flow transmitter calibrations. The inspectors reviewed the corrective action documentation and procedures associated with this event. The inspectors also discussed this event with applicable operations, instrument and control, and engineering personnel.

b. Observations and Findings

On November 7, 1998, operations personnel in the Unit 2 control room observed that the megawatt electric output did not agree with the reactor core thermal power. Subsequently, reactor engineering personnel discovered that three feedwater flow temperature substitute values were installed in the plant monitoring computer system (3D-MONICORE). When the substitute values were removed, reactor thermal power dropped from 98.5% to 92.5% and station personnel recalibrated the APRM channels.

The substitute values were originally installed during reactor feed flow transmitter calibration checks on October 8, 1998 and were not removed following the checks. These correction factors affected the calculated heat balance and resulted in actual core thermal power being less than indicated core thermal power. The errors in the heat balance calculation caused the absolute difference between the APRM channels and the calculated reactor power to be outside of TS surveillance requirements.

Station personnel determined that the primary cause of this event was the failure to properly track and remove the substitute values following completion of the feed flow transmitter calibration checks. The procedures for these checks were changed to ensure that substitute values were removed following calibration. Station personnel also reviewed other procedures that could impact the 3D-MONICORE heat balance calculation and updated them as required to address any generic concerns from this issue. The corrective actions for this issue also addressed training applicable station personnel about the causes and corrective actions from this event.

The inspectors performed an on-site review of the LER and PEP associated with this event. The inspectors determined that station personnel took adequate and reasonable corrective actions for this issue.

Technical Specification Surveillance Requirement (SR) 3.3.1.1.2 requires that the absolute difference between the average power range monitor (APRM) channels and the calculated power be less than or equal to 2% reactor thermal power. This SR is applicable 12 hours after operating at greater than or equal to 25% reactor thermal power.

Contrary to the above, from November 4 until November 7, 1998, the absolute difference between the (APRM) channels and the calculated power was greater than 2% reactor thermal power with reactor thermal power greater than 25%. This condition occurred because substitute feedwater flow temperature correction values had been left in the plant monitoring system during calibration checks of reactor feed flow transmitters on October 8, 1998. These values affected the calculated heat balance and resulted in actual core thermal power being up to six percent less than indicated core thermal power. This non-repetitive, licensee-identified and corrected violation is being treated as an NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV) 50-277/98-11-03**

c. Conclusions

Station personnel discovered that a Technical Specification Surveillance Requirement for average power range monitor channel calibration was not met during Unit 2 power ascension due to an inaccurate heat balance calculation. The heat balance calculation inaccuracy was due to substitute values installed by instrument and control and engineering personnel during flow transmitter calibrations. The calculated heat balance values were always conservative from a safety perspective and station personnel took adequate and reasonable corrective actions for this event. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) VIO 50-277(278)/97-07-02 Three Examples of Procedure Non-Adherence - 3B High Pressure Service Water Pump Maintenance, Station Battery Startup, Cooldown Operation

NRC Inspection Report 50-277(278)/97-07 identified multiple examples where operations and maintenance personnel failed to properly implemented procedures. The station's corrective actions included:

- Adoption of a "back to basics" approach with focus on safety culture, procedure use and work package use
- Increased emphasis on the use of the STAR (Stop, Think, Act, Review) principle during work performance
- More formalized pre-job briefs

The inspectors noted that the back to basics program refocused the way operators and maintenance technicians performed equipment manipulations and worked in the control room and the plant. Self and peer checking by plant personnel have improved procedural and work package adherence. The maintenance organization incorporated a check list into pre-job briefings to improve standardization. The inspectors concluded that these actions have improved the performance of procedure and work package implementation. The inspectors had no additional concerns with this violation.

III. Engineering

E1 Conduct of Engineering

E1.1 ISFSI Pad and Retaining Walls

a. Inspection Scope (60851)

This inspection reviewed independent spent fuel storage installation (ISFSI) engineering design and construction activities associated with the storage pad and retaining walls.

b. Observations and Findings

The inspectors reviewed PECO Energy Calculation No. PS-0959, for the pad where the spent fuel casks will be stored. The inspectors verified the geometric accuracy of the mathematical model, which used a finite element method. The material properties were correctly input in the analysis. PECO used the right seismic ground motion input. Soil structure interaction analysis was adequate; the soil beneath has been analyzed to not liquefy under the safe shutdown earthquake (SSE) ground motion. Assumptions for the calculation and consideration of variability were good. Also, PECO's reinforcement requirements for the pad were reasonably conservative; reinforcement distribution was uniform and symmetric; consideration of soil and load variations to determine maximum moments and shear was good; and the seismic response evaluation was reasonably conservative.

The inspectors reviewed key aspects of PECO calculation PS-0960, regarding the East and West retaining walls. The inspectors found that the design for the retaining walls met the pertinent code requirements established in the Design Input Document (DID) ECR No. 98-0081. The proper critical load combination was applied to the East and West walls, and the associated footings. The methodology used to calculate the reactions were acceptable, and the results showed adequate design margins. The assumptions for the calculation were conservative. This conservatism resulted in additional margins, which were estimated to be 10%.

c. Conclusion

PECO design calculations for the storage pad, east and west walls, and associated footings were prepared in accordance with established design input documents and regulatory guidance. Calculation results met code requirements and were conservative.

E1.2 Reinforced Concrete Bridge over Rock Run Creek

a. Inspection Scope (60851)

This inspection reviewed key aspects of the analysis and design of the reinforced concrete bridge over Rock Run Creek. To enable the transportation of loaded casks from the power block to the storage pad (ISFSI), a cast-in-place, reinforced concrete bridge was constructed over Rock Run Creek.

b. Observations and Findings

The inspectors reviewed PECO Nuclear calculation No. PS-0962, regarding the structural analysis of the Rock Run Creek Crossing Bridge and its supporting abutment, including the supporting piles. The analysis of the bridge used a three dimensional space frame computer program model, using a finite element model. The inspectors found the mathematical model to be accurate, the material properties were correctly incorporated into the mathematical model for the finite element analysis, the loads and the load combination were considered in accordance with American Concrete Institute (ACI)-349 with an acceptance criterion established in NUREG-1567.

The maximum shears and bending moments were correctly used in the design of the piles and beams. However, the inspectors noted that the design of the bridge deck was done using load case 16 and not loaded using load case 14 or 15 which were related to cask drops and have maximum moments. The inspectors questioned the rational of this evaluation. PECO Nuclear noted that in the Design Input Document (DID), the bridge will be designed to withstand a cask drop load without causing permanent deformation of the bridge beam/pile system. Also, some damage can be tolerated provided that timely repairs are made to the bridge deck. The inspectors noted that this "tolerable damage" to the bridge deck was not quantified. PECO Nuclear performed a calculation using the maximum bending moment corresponding to load case 14. This calculation satisfactorily demonstrated that the deck will maintain its structural integrity without any permanent deformation of the rebar. Therefore, the ability of the deck to transfer loads to the beams will be maintained. The inspectors reviewed this calculation and determined that it was acceptable. The thickness of the deck will be increased from 12" to 14" to provide additional protection to the structural members of the bridge.

c. Conclusion

PECO design calculations for the bridge used to transport loaded spent fuel casks, were prepared in accordance with established design input documents and regulatory guidance and were acceptable.

E2 Engineering Support of Facilities and Equipment

E2.1 Reactor Water Cleanup System Automatic Isolations (Unit 2)

a. Inspection Scope (37551, 71707)

The inspectors reviewed two Unit 2 reactor water cleanup (RWCU) system automatic engineered safety feature (ESF) isolation events that took place on September 15, 1998, and on December 1, 1998. Both occurred due to high flow signals generated while operators were returning the system to service.

b. Observations and Findings

On September 15, a RWCU system isolation occurred as reactor operators were opening the RWCU demineralizer bypass valve. Engineers initially determined the cause of the event to be a leaking RWCU dump control valve, CV-2-12-055. Subsequent inspection of CV-2-12-055 and further review by a cross-discipline team led to the conclusion that a problem with the sequence of valve operations in the RWCU system operating procedure, SO 12.1.A-2, "Reactor Water Cleanup System Startup for Normal Operations of Reactor Vessel Level Control," caused a flow spike and was a more likely primary cause of this event. Engineers revised this procedure in November 1998. The team identified a contributing cause to be air entrapment in the differential pressure instrument sensing lines. The inspectors noted that the initial engineering investigation was not sufficiently thorough to recognize the procedure deficiency. The inspectors determined that this procedure deficiency was of minor significance and not subject to formal enforcement action.
On December 1, an RWCU isolation occurred as operators were opening the system inboard and outboard isolation valves. Engineering personnel were continuing to review this event. They were pursuing the following: investigating water hammer effects and air entrapment in instrument sensing lines, installing a temporary modification to determine the magnitude of the pressure/flow spike during opening of isolation valves, and considering installation of switches or jumpers to temporarily bypass the isolation function. The inspectors identified no concerns with the progress of this investigation.

c. Conclusions

Two Unit 2 reactor water cleanup system isolation events that occurred on September 15, 1998 and on December 1, 1998, were not directly related. The licensee's investigation of these events was found to be acceptable.

E3 Engineering Procedures and Documentation

E3.1 Review of the 1997 Annual Report of 10 CFR 50.59 Evaluations

a. Inspection Scope (37001)

The inspectors reviewed the 1997 annual report of 10 CFR 50.59 evaluations and Revision 15 of the Updated Final Safety Analysis Report (UFSAR). This review was performed to determine if the 10 CFR 50.59 reports involved any unreviewed safety questions and verify that the UFSAR had been properly updated.

b. Observations and Findings

On July 23, 1998, PECO submitted its 1997 annual report for Peach Bottom Atomic Power Station, Units 2 and 3, as required by 10 CFR 50.59(b)(2). On May 8, 1998, PECO submitted Revision 15 of the UFSAR, pursuant to the requirements of 10 CFR 50.71(e)(4).

The 1997 report contained descriptions of design changes, and the safety evaluation of the changes that formed the bases for determining that the changes did not involve unreviewed safety questions. The inspectors reviewed a sample of the descriptions provided in the 1997 annual report and found that the description of the changes were adequate and that the changes did not involve unreviewed safety questions.

The inspectors also reviewed a sample of summary reports against the May 8, 1998 UFSAR update, and found that the changes made pursuant to 10 CFR 50.59 were incorporated as updates to UFSAR.

c. Conclusion

Changes summarized in the 1997 annual 10 CFR 50.59 report were adequately described to conclude that they did not involve unreviewed safety questions, and the changes were adequately described in the May 8, 1998 UFSAR update.

E4 Engineering Staff Knowledge and Performance

E4.1 Performance During Challenges to Thermal Limit Margins and APRM Technical Specification Surveillance Requirements

a. Inspection Scope (37551 & 71707)

The inspectors reviewed the safety significance, causes and corrective actions following the discovery of a non-conservative thermal limit calculation for fresh fuel in the process computer data bank. The inspectors also reviewed the role of reactor engineering in the failure to meet the TS surveillance requirements for the APRM channels following startup from the Unit 2 outage. The inspectors observed reactor engineering personnel responding to a step increase in thermal limits values on Unit 3 after a Transversing

Incore Probe (TIP) run and update of the local power range monitors (LPRMs). All three of these issues and related topics were discussed with reactor engineering.

b. Observations and Findings

Non-Conservative Thermal Limit for Maximum Fraction Of Limiting Power Density

During preparation for the development of the PBAPS Unit 2 Cycle 13 process computer data bank, PECO engineering discovered a difference between the as-delivered Cycle 12 data bank and the recent Cycle 12 wrap-up. The difference was in a Control Rod Blade History (CBH) Peaking factor switch. The licensee found that this condition had existed since October 1996 for Unit 2 and October 1997 for Unit 3.

With the incorrect CBH Peaking Factor model, the treatment of the MFLPD thermal limit for fresh fuel was incorrect in the non-conservative direction. The licensee determined through a review of past history that no thermal limits had been exceeded as a result of this error. The non-conservative MFLPD values were a concern only for unit 3, since this was the only unit operating with fresh fuel. Certain individual fresh fuel bundles in unit 3 showed a 9% non-conservative MFLPD value. Since these particular fresh bundles were more than 9% below the core leading exposed bundle, there was no impact on the overall core leading MFLPD for Unit 3. The licensee learned from the vendor that this condition was due to a data bank variable being changed automatically by the 3D MONICORE during the installation of the data bank. Reactor engineers did not recognize, when the first process computer case was run on each unit at the beginning-of-cycle, that the control blade history peaking factor switch automatically changed back to the initial value.

Initial corrective actions included administratively limiting MFLPD to 0.97 or less for both units. Subsequently, PECO engineering completed an update to the 3D MONICORE program for each unit to correct the CBH and permanently reset the peaking factor switch. A post-update test was run to verify that the problem had been corrected, and that the software would not reset the peaking factor value.

The inspectors noted that the 3D MONICORE data bank performs no function which would be required to mitigate an accident or transient. The computer program functions only to monitor thermal limits. A 10CFR50.59 safety evaluation concluded that the update to the data bank would not constitute an unreviewed safety question. The inspectors had no concerns with this evaluation.

The inspectors noted that the licensee initiated a PEP to further investigate this problem but that, as of the end of the inspection, this investigation had not been fully completed. The licensee has determined that a GE information letter regarding the computer program was disseminated to Limerick but not Peach Bottom. Therefore the automatic changing of the control blade history peaking factor was not recognized by Peach Bottom personnel.

Failure to Meet Technical Specification Surveillance Requirements for the Absolute Difference in the APRM Channels and the Calculated Reactor Power

As discussed in Section M4.1, station personnel discovered that a TS surveillance requirement involving calibration of the APRM channels had not been met during Unit 2 power ascension due to an inaccurate heat balance calculation. This event was caused by the failure to properly track and remove substitute values that input into the 3D MONICORE heat balance calculation. This resulted in a non-cited violation.

The inspectors noted that a contributing cause for this event was that licensee procedures did not provide for alternate means to verify 3D MONICORE heat balance accuracy. As part of the corrective actions for this event, reactor engineering personnel created a core thermal power monitoring procedure to provide alternate methods to verify the accuracy of reactor power calibrations.

Unexpected Thermal Limit Increase Following Traversing Incore Probe (TIP) 3D MONICORE Update

On December 14, 1998, I&C technicians performed a TIP run on Unit 3 for the LPRM gain calibration. When the TIP data files were uploaded into the 3D MONICORE computer program for calculation of the thermal limits, the values for Maximum Fraction of Limiting Power Density (MFLPD) increased. The new value was 0.983 which was above PECO's administrative limit of 0.980. Prior to the TIP run, the core leading MFLPD value was 0.950. The control room operators informed reactor engineering as required by procedure. Fuel and Services Division and Reactor Engineering personnel began the development of a control rod pattern adjustment to increase thermal limit margin while trending MFLDP. Reactor engineering did not expect the sudden increase in MFLPD as a result of the initial change in the control rod pattern and TIP run and contacted the fuel and 3D MONICORE vendor to determine the possible causes for this increase.

MFLPD continued to increase until it reached 0.992, which was above the 0.990 action level specified in operations procedures. Reactor power was reduced 25 MWth which caused MFLPD to lower to a value of 0.958. Subsequently, operators made a control rod pattern adjustment and continued to monitor thermal limits.

The inspectors observed reactor engineers monitoring thermal limits values and providing guidance for the reduction of reactor power and subsequent control rod pattern adjustments. The inspectors determined that the reactor engineers responded appropriately during these evolutions. Based on review of the transient parameters, the inspectors determined that no technical specification limits were violated. The inspectors noted that station administrative procedural guidance provided margin to ensure these thermal limit requirements were not exceeded.

Reactor engineering planned to provide procedural guidance to prevent the sequences that could lead to sudden MFLPD increases. They were also investigating other possible corrective actions to prevent this condition.

c. Conclusions

Three reactor core thermal management problems occurred during this inspection period related to the 3D MONICORE program. Two problems were related to configuration management of input data to the program and one was related to unexpected program results. The licensee investigated these problems and took appropriate initial actions and developed appropriate corrective actions. No thermal limits were exceeded as a result of these problems.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) URI 50-277(278)/96-06-02 Station Blackout (SBO) Line Review

On July 9, 1996, members of the Nuclear Reactor Regulation (NRR) staff reviewed the implementation of PECO's commitment to 10 CFR 50.63 "Station Blackout." The NRR inspectors toured the Conowingo Hydroelectric Station, which is the generation source for the Peach Bottom SBO line. The inspectors were concerned that at times no Conowingo hydro units, that could supply the SBO line, were generating power or being used as electrical condensers (spinning reserve). The inspectors questioned how reliability of the line was monitored since there were times when no units were operating or spinning. The inspectors were also concerned that a wooden utility pole was used at the Susquehanna Substation where the SBO line leaves the breaker and goes underground. The inspectors questioned how the use of a wooden pole was consistent with the stated design criteria for weather-related events.

The licensee informed the inspectors that during a station blackout, Peach Bottom would be started from a "black start" since the Conowingo generating units and condensing units trip when a blackout occurs. The station has shown that the SBO line can be manually connected to supply the startup bus in less than 1 hour which meets the SBO commitment requirements. Therefore, hydro units were not required to be operating or on spinning reserve at all times. Also, the SBO equipment, from the buses at Conowingo to the Peach Bottom switchgear, were included in the 10 CFR 50.65 "Maintenance Rule" program. The reliability of this equipment is monitored through the maintenance rule. The inspectors determined that this met the SBO rule criteria and addressed this concern.

The licensee notified the inspectors that the severe weather assumptions made in the original design of the wooden utility pole were bounded by the most likely weather-related events. Therefore, the inspectors determined that the pole met the requirements as stated in the original design of the SBO line and met the SBO rule. The inspectors had no additional concerns with this issue.

IV. Plant Support

R1 Radiation Protection and Chemistry Controls (RP&C)

R1.1 Locked High Radiation Doors and Posting Inspections During Plant Tours

a. Inspection Scope (71750)

The inspectors toured the Unit 2 and 3 turbine and reactor buildings during the inspection period and verified that high radiation doors were properly posted and locked, if required.

b. Observations and Findings

The inspectors tested approximately 25 high radiation doors that were required to be locked. The inspectors also observed numerous radiological postings throughout the Unit 2 and 3 turbine and reactor buildings. All high radiation doors required to be locked were found locked. No deficiencies were noted with the radiological postings. All locked high radiation doors tested and postings observed met the requirements of Technical Specification 5.7. No concerns were identified by the inspectors.

c. Conclusions

Locked high radiation doors and postings in the Unit 2 and 3 turbine and reactor buildings, observed during this inspection period, were adequately maintained per technical specification and plant administrative requirements.

R4 Staff Knowledge and Performance in RP&C

R4.1 Radiation Protection Controls During High Radiation Work Activities

a. Inspection Scope (71750)

The inspectors observed radiation protection controls during removal and hydrolyzing of control rod blade components in the Unit 3 spent fuel pool and replacement of a Unit 2 traversing incore probe (TIP). The inspectors also reviewed the applicable radiation control planning and As-Low-As-Reasonably-Achievable (ALARA) awareness at the job site.

b. Observations and Findings

The inspectors observed the performance of radiation protection personnel during the Unit 3 spent fuel pool work and replacement of the Unit 2 TIP. Radiation protection personnel were actively overseeing these activities and monitoring worker dose using a remote monitor. The inspectors observed good awareness of ALARA during these jobs and effective planning, which resulted in low doses for these activities.

c. Conclusions

Radiation protection personnel provided very good oversight of control rod blade component removal from the Unit 3 spent fuel pool and replacement of a Unit 2 traversing incore probe. Good awareness for As-Low-As-Reasonably-Achievable (ALARA) by personnel involved with this work, and effective planning and monitoring by radiation protection personnel resulted in low doses for these activities.

S2 Status of Security Facilities and Equipment

S2.1 General Integrity of Protected Area (PA) Barriers and Inspection of Central Alarm Station (CAS) and Secondary Alarm Station (SAS)

a. Inspection Scope (71750)

The inspectors toured the site perimeter to observe the condition of the PA barriers and the isolation zones around the PA barriers. The inspectors also toured the Central Alarm Station (CAS) and the Secondary Alarm Station (SAS) to verify that the site was maintaining the appropriate alarm, surveillance, and communication capabilities and that no activities in the CAS would interfere with the execution of the detection, assessment and response function.

b. Observations and Findings

The inspectors observed that the protected area barrier had no openings and was not damaged or degraded and appropriately maintained. The barrier did not show any sign of erosion at the base and there were no substantial rock debris accumulations against any of the fences. The isolation zones were free of objects and permitted observation by CAS and SAS operators.

The CAS and SAS alarm, surveillance, and communication capabilities were being appropriately maintained and no activities in these areas interfered with the execution of the detection, assessment or response functions.

c. Conclusions

The licensee had appropriately maintained the barriers and isolation zones around the protected area. Security equipment in the Central Alarm Station and Secondary Alarm Station areas were functioning properly. Activities in these areas would not have interfered with the execution of the detection, assessment or response functions.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the results of the inspection to members of licensee management on January 8, 1999. The licensee acknowledged the findings presented. No proprietary information was identified by the licensee.

ATTACHMENT 1

LIST OF ACRONYMS USED

AO	abnormal operating
APRM	Average Power Range Monitor
AR	action request
BTP	Branch Technical Position
CAS	Central Alarm Station
CBH	control rod blade history
CM	Corrective Maintenance
CRD	Control Rod Drive
CS	Core Spray
DID	Design Input Document
DOT	Department of Transportation
ECR	Engineering Change Request
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
FCR	Field Change Request
FIN	Fix-It-Now
FLLLP	Fraction of Limiting Load Line Power
GP	general procedure
ISFSI	independent spent fuel storage installation
ITS	Improved Technical Specifications
JPM	Job Performance Measure
LCO	limiting condition for operation
LER	licensee event report
LOCA	loss of coolant accident
LORT	Licensed operator requalification training
LPRM	Local Power Range Monitor
LSRO	Limited Senior Reactor Operator
MCRD	Main Control Room Deficiency
MFLPD	Maximum Fraction of Limiting Power Density
MOV	motor operated valve
NCV	non-cited violation
NOTICE	notice of violation
PBAPS	Peach Bottom Atomic Power Station
PECO	PECO Energy
PECON	PECO Nuclear
PEP	performance enhancement program
PDR	public document room
PMT	Post-Maintenance Testing
RO	Reactor Operator
RP	radiation protection
RPM	radiation protection manager
RWCU	reactor water cleanup
RHR	residual heat removal
RT	Routine Test

RWM	Rod Worth Minimizer
SAS	Secondary Alarm Station
SBO	Station Blackout
SR	Surveillance Requirement
SSE	Safe Shutdown Earthquake
ST	surveillance Test
TS	technical specification
TSA	technical specification action
UFSAR	updated final safety analysis report
URI	Unresolved Item

INSPECTION PROCEDURES USED

IP 37001	10 CFR 50.59 Safety Evaluation Program
IP 37551	Onsite Engineering Observations
IP 60851	Design Control of IFSFI Components
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71001	Licensed Operator Requalification Program Evaluation
IP 71707	Plant Operations
IP 71750	Plant Support Observations
IP 92903	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Open

None

Opened/Closed

50-277/98-11-01	NCV	Loss of Off-site Power Source and 2SU Bus Trip Due to Electrical Bus Switching to Support Planned Breaker Maintenance (Section O3.1)
50-277/98-11-02	VIO	Failure of Certain Licensed Operators to Complete Requalification Training and Inaccurate License Renewal Application Submitted to the NRC (Section O5.1)
50-278/98-11-02	VIO	Failure of Certain Licensed Operators to Complete Requalification Training and Inaccurate License Renewal Application Submitted to the NRC (Section O5.1)
50-277/98-11-03	NCV	Failure to Meet Technical Specification Surveillance Requirements for the Absolute Difference in the Average Power Range Monitor Channels and the Calculated Reactor Power (Section M4.1)

Closed

50-277/2-98-007	LER	Failure to Meet Technical Specification and Associated LCO Requirements of the Absolute Difference in Average Power Range Monitor and Calculated Power of Less Than or Equal to 2 Percent (Section M4.1)
50-277/2-98-008	LER	Loss of Off-site Power Source and 2SU Bus Trip Due to Electrical Bus Switching to Support Planned Breaker Maintenance (Section O3.1)

50-277/98-04-01	URI	Failure of Certain Licensed Operators to Complete Requalification Training (Section O5.1)
50-278/98-04-01	URI	Failure of Certain Licensed Operators to Complete Requalification Training (Section O5.1)
50-277/96-06-02	URI	Station Blackout Line Review (Section E8.1)
50-278/96-06-02	URI	Station Blackout Line Review (Section E8.1)
50-277/97-08-01	VIO	Cold Weather Preparations Procedural Non-Compliance (Section O8.1)
50-278/97-08-01	VIO	Cold Weather Preparations Procedural Non-Compliance (Section O8.1)
50-277/97-07-02	VIO	Three Examples of Procedure Non-Adherence - 3B High Pressure Service Water Pump Maintenance, Station Battery Startup, Cooldown Operation (Section M8.1)
50-278/97-07-02	VIO	Three Examples of Procedure Non-Adherence - 3B High Pressure Service Water Pump Maintenance, Station Battery Startup, Cooldown Operation (Section M8.1)

Attachment 2

SYNOPSIS - NRC OFFICE OF INVESTIGATIONS REPORT NO. 1-98-020

On April 24, 1998, the NRC Office of Investigations (OI) Region I(RI), initiated an investigation regarding an allegation that four Peach Bottom Atomic Power Station (PBAPS), NRC licensed operators had not attended all required training, including makeup training, and therefore, did not complete the PBAPS Licensed Operator Requalification Training (LORT) program during the April 1994, to April 1996, two-year cycle, as required by NRC regulations. it was further alleged that licensed operator applicant Personal Qualification Statements (NRC Form 398s) submitted by the licensee for two of those individuals, are inaccurate, based on their failure to complete LORT.

Based on the evidence developed during the investigations, OI:RI concludes that three of the licensed operators did not attend all of the requalification training, and, thus, did not complete the LORT program, in violation of NRC regulations. It could not be substantiated that the licensed operators deliberately failed to complete the LORT program, or that the facility licensee (PBAPS) deliberately violated NRC regulations regarding LORT. Also, based on the failure to complete the LORT, it is concluded that one 398 is inaccurate, but it could not be substantiated that the 398 was deliberately and knowingly made false when it was sent to the NRC.