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U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Subject: Peach Bottom Atomic Power Station Units 2 & 3
Response to Notice of Violations (Combined Inspection Report No. 50-277/96-01 & 50-278/96-01)

Gentlemen:

In response to your letter dated March 25, 1996, which transmitted the Notice of Violations concerning the referenced inspection report, we submit the attached response. The subject report concerned a Routine Resident Integrated Safety Inspection that was conducted January 14 through March 9, 1996.

If you have any questions or desire additional information, do not hesitate to contact us.

Thomas N. Mitchell
Vice President,
Peach Bottom Atomic Power Station

Attachments

cc: B. W. Gorman, Public Service Electric & Gas
R. R. Janati, Commonwealth of Pennsylvania
T. T. Martin, US NRC, Administrator, Region I
W. L. Schmidt, US NRC, Senior Resident Inspector
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R. I. McLean, State of Maryland
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CCN# 96-14038

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RESPONSE TO NOTICE OF VIOLATIONS

Restatement of Violations

A. 10 CFR 50, Appendix B, Criterion XI, Test Controls requires, in part, that components be tested in accordance with written test procedures that incorporate acceptable limits contained in the applicable design documents.

Contrary to the above, since 1989, PECO did not implement adequate functional or calibration testing, in that acceptance criteria in the written test procedures did not verify that the 98% and 89% degraded bus undervoltage relays would function within the Technical Specification allowable limits.

This is a Severity Level IV violation (Supplement I).

B. 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions requires, in part, that measures be established to assure prompt identification of conditions adverse to quality.

1. Contrary to the above, since 1989, PECO had calibration data that indicated that the 98% and 89% degraded bus undervoltage relay setpoints were found to be outside of the Technical Specification allowable values and did not take appropriate actions to correct the issue.

2. Contrary to the above, PECO did not properly identify or implement corrective actions to identify and correct an adverse circuit breaker position that caused portions of the Unit 2 Remote Shutdown Panel to not receive alternate control power for over a year. This failure led to several functions of the remote shutdown panel being inoperable from October 1994 through January 1996.

Both examples constitute a Severity Level IV violation (Supplement I).

Response to Violation A and B.1. - Background

On January 23, 1996, the NRC Senior Resident Inspector questioned the adequacy of the 4 kV undervoltage (UV) relay functional test series SI2(3)K-54-E(bus number)-XXFM. The test procedures utilized a test voltage value for the 98% and 89% degraded grid UV relays that were lower than allowable values identified in Custom Technical Specifications (CTS) and Improved Technical Specifications (ITS). At the time the functional testing was questioned, ITS had been implemented for approximately one week. The previous CTS definition of functional testing was interpreted to test the relays as "verify the proper instrument channel response, alarm or initiating action." Test values were selected below the actual CTS allowable values to ensure that the relays were functional and any associated response or action was initiated. The need to perform testing within the actual test band in CTS was considered not to be required since the purpose of the test was interpreted as a functional test only. With the implementation of ITS however, the definition was clarified to require the test to verify relay operability. The difference between testing philosophies was not implemented during the transition to ITS, and UV relay functionality testing continued with the same testing methodology utilized during CTS. Test voltage values continued to be selected for functional testing below ITS allowable values even though setpoint verification was now required to ensure relay operability.

Following the identification of this problem, it was discovered that the Updated Final Safety Analysis Report (UFSAR) Section 8.4 - Auxiliary Power Systems, Sub-section 8.4.7 - Inspection and Testing, provided additional information that the original philosophy adopted concerning functionality testing was incorrect. Testing should have always been performed to verify proper settings, operability, and functional performance of the relays. The tests should have been written to provide assurance that the UV protection scheme would operate at the required voltage and time settings, and perform the intended functions when called on to operate.

Calibration testing of the 4 kV UV relays was required by CTS and ITS to be performed every eighteen months. This was accomplished by the performance of SI2(3)K-54-E(bus number)-XXCE "Calibration Check of E (bus number) 4 kV undervoltage relays". Technicians would remove the appropriate relay from service to be calibrated and replace it with a calibrated spare. The relay was then taken and bench tested. I&C technicians were required to stop the test and notify Shift Management and I&C Supervision if the relay was found to be out of calibration or any procedure step produced results which would indicate the instrument is inoperable or outside of Technical Specification limits. Following this notification, the relays were re-calibrated and re-installed. In addition, the failure and subsequent re-calibration of the relay was required to be documented as a FAIL/PASS in the calibration procedure. By documenting the test as a FAIL/PASS, the equipment would be re-calibrated and left operable at the end of the calibration procedure.

This resulted in a condition where the as-found data was not tracked or trended to identify repetitive failures of redundant equipment. Since the functional test did not perform an actual "calibration check" within the appropriate Technical Specification allowance values and the initial as-found calibration failures were not tracked and trended, problems associated with the existing functional testing and calibration methodology went unrealized.

Reasons for the Violations

Additional information located in the UFSAR was not properly utilized to clarify the definition of Functional Testing in CTS. As a result, 4 kV UV relay functional testing was incorrectly interpreted and not properly performed within the appropriate test bands as stated in CTS.

Change management and transition planning during ITS implementation did not adequately address the required methodology change and associated issues that was required for 4 kV UV relays. This resulted in functional testing that was not performed within the appropriate test bands in ITS and in accordance with guidance provided in the UFSAR.

There was no mechanism to track or trend the as-found instrument failures that were later re-calibrated (FAIL/PASS) during the calibration process to assess the condition of the equipment or when corrective actions were needed. Since the frequency of the calibration procedure was once every eighteen months and the relays were scheduled individually at different times, the results of the calibration data for the 4 kV UV population and potential common problems were never evaluated. As a result, problems associated with the 4 kV UV relays were not identified and corrected.

The Corrective Steps That Have Been Taken and the Results Achieved

The 4 kV 98% and 89% UV relay functional test series SI2(3)K-54-E(bus number)-XXFM were revised to ensure that functional testing is performed within the ITS allowable limits. During this revision process, it was discovered that the allowable values in ITS for the 4 kV bus undervoltage function may have been values used in the actual design calculations and were actually analytical limits rather than allowable values as described in the bases. As a precautionary measure, the revised procedures currently include acceptance criteria that is more restrictive than ITS requires. In addition to tightening the tolerances of the actual test range within the ITS range, additional margin has been realized prior to being outside the analyzed region. The revised tests now require the relays to be functionally tested by performing a one point calibration check where the as-found setpoint is obtained and verified within the acceptance criteria. As a result, the trip point verification of the relays is now performed on a monthly basis. The previous functional test only verified the relay actuated below its lower limit.

Subsequent functional testing was performed on the 4 kV 98% and 89% UV relays to ensure that the relays were properly calibrated. As a result of this testing, it was determined that trip settings for nine relays were below their ITS allowable minimum voltage. The relays were determined to be within the analyzed limits and able to perform their safety function. Following successful re-calibration, the relays were returned to service. This event was reported in Licensee Event Report 2-96-002, dated February 23, 1996. Following functional testing and appropriate re-calibration, all 4 kV 98% and 89% UV relays were operable in the as-left condition.

A Performance Enhancement Process investigation was initiated to evaluate and determine the circumstances and causes of the event. Results of that investigation were used for this report.

This event and the lessons learned were discussed with I&C electrical team members on January 30, 1996. In addition, this event and the Improved Instrument Setpoint Control Program was presented during Engineering Support Personnel Continuing Training (ESPCT) during March and April, 1996.

A computer report has been implemented to track as-found test data that is outside appropriate functional performance or calibration test criteria. This report is issued by the ST Coordinator and includes any instrument functional or calibration test where the instrument fails the initial as-found test criteria and is successfully re-calibrated and left in an operable condition (FAIL/PASS). Instruments that fail the initial as-found criteria and can not be successfully re-calibrated (FAIL/FAIL) are also included in this report. This report enables personnel to track and trend instrument test reliability and indicates potential adverse results where investigation and possible corrective actions may be necessary.

The Corrective Steps That Will Be Taken To Avoid Further Violations

The corrective steps that have been taken will avoid further violations.

Date When Full Compliance Was Achieved (Violation A)

Full compliance was achieved on January 26, 1996, after the 4 kV UV relay functional test series SI2(3)K-54-E(bus number)-XXFM for 98% and 89% relays were revised to address proper testing methodology to ensure the relays would function within the ITS allowable limits.

Date When Full Compliance Was Achieved (Violation B.1)

Full compliance was achieved on April 22, 1996, when a report was implemented to track initial as-found instrument test data outside appropriate functional performance or calibration test criteria. Individual instrument and group test reliability is monitored to ensure and potential adverse results are proper identified and evaluated.

Response to Violation B.2. - Background

On October 4, 1994, a clearance was applied to the 125 volt DC circuit breaker (20D024 cir 14) for the installation of motor-operated valve MO-2-10-17 pressure switch per modification 5194. This breaker supplies alternate power to the MO-2-10-17 valve when the valve is operated from the remote shutdown panel. The clearance was removed on October 9, 1994. The clearance specified that the circuit breaker be left in the open position contrary to the direction given in the system check-off list (COL). The clearance also specified that the normal valve power supply breaker be left in the open position contrary to the system COL. There were no special instructions or reasons documented in the clearance why the breakers were not returned to their normal configuration. It is believed that the circuit breakers may have been left open pending completion of a rotational check of MO-2-10-17. The normal power supply breaker was apparently closed later to support the rotational check. Since the alternate power supply was not required to conduct the rotational check, its breaker was never closed. There are no lights or alarms in the control room to alert Operations that the breaker was open. Valve position indication lights at the remote shutdown panel also remain off until control is transferred to the remote shutdown panel. Therefore, routine observation of the remote shutdown panel would not indicate that the breaker was left open.

On October 19, 1994, during a normal refuel surveillance test ST-0-013-750-2 "Emergency Shutdown Control Panel Test", various components did initiate the control transfer alarm, but did not give position indication at the remote shutdown panel when their switches were taken to a "pulled" (remote) position. The interpretation at this time was that the position indication was not a Technical Specification requirement or prerequisite for declaring the surveillance test satisfactory. Receipt of the transfer alarm may have provided a reason to conclude that switch function was maintained despite the loss of the position indication, however, the alarm only alerts the control room operators to a change in remote shutdown panel switch position and does not give a valid indication of the operability of the switch function. An action request (AR) was initiated to document the position indication problems and the ST was signed off as satisfactorily completed on October 19, 1994. When the system manager received the AR, the perceived expectation at that time was that the system managers provide assistance in scheduling work. The assumption was that all the troubleshooting to evaluate the problem had already been completed. The system manager concluded no further action was required and dispositioned the A/R to after 1995 refuel outage. In December, 1995, the AR was re-assigned to a new system manager. Because of past experience with transfer switch contacts being dirty, the system manager thought that this was another occurrence. Since the contacts are only operated every two years and they need to be exercised to be cleaned, the system manager responded to the AR by recommending the switches be exercised. If after being exercised, indication was not received on the remote shutdown panel, it was recommended that the switches be cleaned. It was only after discovery of the breaker not being in its normal system line-up that the cause of the failed position indication on the remote shutdown panel was realized.

Reasons For The Violation

Administrative requirements for system restoration were not met. The operator who specified the clearance restoration sequence did not properly restore the breaker to the position specified by the system COL. This did not meet the expectation in the Operations Manual which requires appropriate operating procedures, including COLs, to be used to return equipment to service.

The routine surveillance test procedure did not include appropriate required steps (black box steps) that would have alerted personnel that the lack of position indication may be an indication of system inoperability, even though the transfer alarm was received.

The system manager perceived that his responsibility to the original AR was only to provide assistance in scheduling work. He made an assumption that all troubleshooting to resolve the problem had been completed. Based on previous experience, an assumption was made that the problem with the switches position indication was a result of dirty contacts.

Operations review of ARs prior to startup did not cause the issue to be investigated further since the ST was signed off satisfactorily and switch position indication was not interpreted as a tech spec requirement.

The Corrective Steps That Have Been Taken and The Results Achieved

The 125 volt DC circuit breaker (20D024 cir 14) was returned to its proper configuration upon discovery of the abnormal position.

A Performance Enhancement Process investigation was initiated to evaluate and determine the circumstances and causes of the event. Results of that investigation were used for this report.

Troubleshooting, maintenance and testing (TMTs) were performed on the appropriate control switches which failed to give positive indication at the remote shutdown panel when the switches were taken to a "pulled" position. All of these switches were verified to be operable by pulling the control switch and verifying loss of indication in the control room and appropriate indication on the remote shutdown panel. The switch was then returned to normal and all normal indications were observed.

ST-0-013-750-2(3) was revised January 30, 1996, which added a black box required step that verified each control switch indication in data table 2 of the test is satisfactory before the test is declared satisfactory.

Expectations for system managers regarding system discrepancies or problems clearly focus on accountability, ownership, and resolution of anomalies. System Managers are required to thoroughly evaluate and resolve all problems associated with their respective systems.

This event was presented as a case study at the Shift Managers meeting on March 22, 1996. Areas of learning and management expectations were discussed.

The Corrective Steps That Will Be Taken To Avoid Further Violations

The corrective steps that have been taken will avoid further violations.

Date When Full Compliance Was Achieved

Full compliance was achieved on January 5, 1996, after the 125 volt DC circuit breaker 20D024 cir 14 was returned to its normal close position.