UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323

Report No.: 50-400/86-93

Licensee: Carolina Power and Light Company
P. O. Box 1551
Raleigh, NC 27602

Docket No.: 50-400 License No.: NPF-53

Facility Name: Harris

Inspection Conducted: December 15 - 17, 1986

Inspectors: L J Watson for 2/18/87
C. L. Vanderniet, Team Leader Date Signed

Team Members: F. R. McCoy
L. J. Watson

Approved by: L J Watson for 2/18/87
M. B. Shymlock, Chief Date Signed
Operational Programs Section
Division of Reactor Safety

SUMMARY

Scope: This routine, unannounced inspection was in the area of event followup.

Results: One violation was identified concerning failure to follow approved procedures.

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REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *A. Howe, Regulatory Compliance
   *E. Steudel, Special Projects
   *C. L. McKenzie, Quality Assurance/Quality Control
   *G. L. Forehand, Quality Assurance/Quality Control Director
   *B. Morris, Technical Support
   *J. R. Sipp, Manager, Effluent and Radiological Control
   *T. Morton, Maintenance Supervisor
   *J. P. Thompson, Operations Supervisor
   *G. T. Lew, Special Projects
   *G. Campbell, Manager-Maintenance
   *R. B. Van Meter, Manager, Technical Support
   *W. R. Wilson, Technical Support
   *C. R. Gibson, Director Plant Programs and Procedures
   *J. H. Smith, Operations Support Supervisor
   *H. W. Bowles, Director, Onsite Nuclear Safety
   *D. L. Tibbits, Director, Regulatory Compliance
   *J. L. Harness, Assistant Plant General Manager

   Other licensee employees contacted included engineers, technicians, operators, mechanics, and office personnel.

   NRC Resident Inspectors

   *S. P. Burris
   *G. Maxwell

   *Attended exit interview

2. Exit Interview

   The inspection scope and findings were summarized on December 17, 1986, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings. No dissenting comments were received from the licensee. Although proprietary material was reviewed during the inspection, no proprietary information is contained in this report.

3. Licensee Action on Previous Enforcement Matters

This subject was not addressed in the inspection.

4. Unresolved Items

Unresolved items were not identified during this inspection.

5. Review of Overpressurization Event of December 3, 1986

The inspector reviewed the overpressurization event which occurred on December 3, 1986, and resulted in the lifting of Reactor Coolant System (RCS) pressure relief valve nine times. The event was recorded in Significant Operational Occurrence Report (SOOR), number 86-011 and Plant Incident Summary, number 86-046. The event was caused by the isolation and depressurization of instrumentation lines to RCS pressure transmitter 1-PT-402, by Instrumentation and Control (I&C) technicians performing Maintenance Surveillance Test (MST) I0322, Reactor Vessel Level Monitoring System Transmitter Calibration.

The Reactor Vessel Level Indication System (RVLIS) was isolated from the RCS at approximately 1700 on December 3, 1986. The isolation of RVLIS was accomplished by shutting and tagging valves 1RC-980, 1RC-981, 1RC-982, and 1RC-983 which isolated level transmitters 1LT-1310, 1LT-1311, 1LT-1312, 1LT-1320, 1LT-1321, and 1LT-1322 as intended. The isolation, however, also isolated two pressure transmitters 1-PT-402 and 1-PT-403. The isolation of the pressure transmitters was not realized by the control room operators however, and eventually caused the Control Operator (CO) to take corrective action for an indicated loss of RCS pressure when the transmitters were depressurized along with the RVLIS level transmitters during the course of performing surveillance activities per MST-I0322.

In accordance with Administrative Procedure (AP) 20, Revision 1, Clearance Procedure, the Shift Foreman is to carefully review all requests for a clearance to evaluate the clearance's impact on the plant. The inspector interviewed the Shift Foreman to determine if such a review had been completed. The Shift Foreman stated that he did a cursory review of MST-I0322 but was relying on Attachment 1 to the procedure which listed all the equipment that would be effected by the test. Attachment 1, however, did not list 1-PT-402 or 1-PT-403. Through discussions with licensee management, the inspector determined that Attachment 1 to MST-I0322 had recently been added to the MST and was only intended as a reference for the operators to use when the MST itself was in the field being performed to remind them of the effected equipment. The Shift Foreman was not aware of this intended function and assumed it was a complete listing. AP-20 further requires the "Tag Preparer" to use approved plant drawings to prepare the tagout. A proper review of the plant drawings listed on MST-I0322 by either the Shift Foreman or the Tag Preparer would have indicated the presence of the two pressure transmitters and prevented the running of MST-I0322 until the effect of the transmitter isolation and subsequent depressurization could have been completely evaluated. The failure to adequately review MST-I0322 is a failure to properly implement AP-20 which is a violation of Technical Specification 6.8.1. For the purposes of this report this is identified as an example of violation 50-400/86-93-01.

Pressure transmitters 1-PT-402 and 1-PT-403 provided pressure indication on the Main Control Board (MCB) for the Control Operator (CO) on 1-PI-402.1, 1-PI-402A and 1-PI-403.1. The CO is required to monitor RCS pressure on 1-PI-402A per step 2 of General Procedure (GP) 001, Section 4.0, Precautions and Limitations. However, with the respective pressure transmitters isolated, the CO was unable to monitor actual RCS pressure using the required indicator. The licensee stated that true RCS pressure was monitored because the shut isolation valves leaked by enough to allow RCS pressure oscillations to be seen on the indicator. The inspector interviewed individuals involved in the event and was told that only one of the isolation valves leaked by, and while performing the test the valve's process line was disconnected from the downstream fluid isolator to ensure system isolation. As a result the inspector considers that the CO was apparently unable to monitor true RCS pressure for some period during the performance of the MST. However, because the CO was unaware of the isolation of the pressure transmitters, the inspector considers his actions correct for the indication he received.

The inspector also reviewed the controls used on the instrument line which was disconnected from the fluid isolator. This line comes from a one inch connection tapping directly off the RCS loop C hot leg through an isolation valve and reducer down to a 3/8 inch process line. The isolation valve is closed only during maintenance and must be manually operated. The process line is connected to a fluid isolator which separates the RCS from the rest of the fluid used in RVLIS. MST-I0322 required a vent plug be removed from the RCS side of the five fluid isolators and a test apparatus installed in this opening. This procedure was followed on four of the fluid isolators, however, the other fluid isolator had the leaking isolation valve so when the vent plug was removed RCS water continued to leak out of the vent. This leak prevented the I&C technician from attaching the test apparatus. The I&C technician informed the I&C Foreman on the scene of this problem and he authorized the removal of the RCS process line. The inspector interviewed the I&C Foreman about this change in the procedure and was told that no procedure change was required because the removal of the process line was within the skill of the technician. The inspector reviewed Maintenance Management Manual (MMM) 001, Maintenance Conduct of Operations, which indicates that the Foreman can determine if work is within the skill of the technician and if so, does not need to request a temporary change to the procedure. The inspector also determined that no QC hold points are required by MMM-001 to insure cleanliness of the RCS piping under four inches in diameter. The inspector considers that some measure should have been taken to inform control room personnel of the removal of the process line, and that some type of an evaluation should have been completed due to the line being a RCS pressure boundary. However, the process by which work was completed under MST-I0322 appeared to be fully within the procedures of the licensee and within the technical requirements of ASME Section XI. The licensee did note the expanded scope of the work on the work order, and the area where the fluid isolator is located was confirmed in an interview, to have been inspected on the at pressure walkthrough and no leakage was found.

When the process line to 1-PT-402 was vented, pressure indication on 1-PI-402A was seen to fall to zero by the CO. This prompted the CO to take corrective action consistent for the pressure indication observed. MST-I0322 contained Attachment 1, Operator Prerequisite Summary Sheet, which was intended to list all instrumentation effected by the running of the MST. The attachment, however, did not list 1-PI-402.1, 1-PT-403.1, or 1-PI-402A which was required to be in use per GP-001. Because the attachment had been included in MST-I0322, the Shift Foreman did not fully review the procedure but, instead relied on the attachment to list all affected equipment. The maintenance staff had intended that the attachments were to be used only as a quick check guide for the operators and in no way intended the attachment to be a substitute for a complete procedural review. The incompleteness of the attachment and miscommunication between maintenance and operations management and staff resulted in the operator challenging the RCS pressure relief valve nine times.

6. Review Of Strip Chart Recorders

The inspectors reviewed the strip chart recorders used on the MCB at the facility. The inspectors noted several cases where the strip charts had not been reviewed and initialed. The inspectors also observed that the pressurizer pressure recorder was out of paper between December 13, 1986, and December 16, 1986. The inspectors are concerned about the lack of attention in this area, because during followup of events or transients this type of information is valuable.

7. Review of Control Rod Testing Events

On December 6, 1986, the licensee made notification of a reactor trip pursuant to 10 CFR 50.72. The event which predicated the trip involved the removal of more than one control or shutdown bank from the fully inserted position with an inoperable Digital Rod Position Indication (DRPI) system. This condition was contrary to Technical Specification special test exception 3.10.5 which was in effect at the time of the event. When the event occurred it was immediately recognized by the Shift Technical Coordinator and action was immediately taken to open the reactor trip breakers in accordance with the action statement for Technical Specification 3.10.5. At the time of the event the licensee was performing mechanism timing tests in accordance with Startup Procedure 1-9101-S-06, Revision 1, Change 3, Rod Drive Mechanism Timing Test - RCS Cold. This test had been scheduled to be performed prior to rod drop time testing and consequently prior to DRPI calibration which can be performed simultaneously with rod drop time measurement testing.

Technical Specification special test exception 3.10.5 allows rod drop time measurement to be performed with DRPI inoperable provided that, for initial calibration of DRPI only, only one shutdown or control bank is withdrawn from the fully inserted position at a time and Keff is maintained at less than or equal to 0.95. For other than initial calibration of DRPI, only one shutdown or control bank can be withdrawn from the fully inserted position at a time and DRPI must be operable during the withdrawal of the rods. This condition of operability is determined by Technical Specification surveillance requirement 4.10.5 which states that the required position indication system shall be determined to be operable within 24 hours prior to the start of rod drop testing and at least once per 24 hours thereafter during rod drop time measurements by verifying the demand rod position indication system and the DRPI system agree within 12 steps when rods are stationary and 24 steps during rod motion.

The inspectors noted that the test exception applied to rod drop time measurement testing and not mechanism timing tests and consequently considered that the licensee improperly invoked special test exception 3.10.5. The licensee stated that they had interpreted mechanism timing tests to be a part of rod drop time measurement testing even though the two tests are performed by different procedures. The licensee stated that generic Westinghouse guidance recommended performance of mechanism timing tests prior to rod drop time measurement testing (and consequently prior to DRPI calibration) to confirm satisfactory operation of the slave cycler and gripper prior to exercising control rods over full cycle. As explained further in this report, this interpretation of Technical Specifications was not shared by all personnel involved in this test. In particular, personnel involved with writing and revising the mechanism timing test procedure did not consider that special test exception 3.10.5 could be invoked for mechanism timing tests and believed that DRPI would consequently be operable during this test. These personnel stated that they were not aware that mechanism timing tests were to be performed with DRPI inoperable. In support of the interpretation that mechanism timing tests were a part of rod drop time measurements, the lead test engineer, shift test coordinator, and shift test foreman prepared and approved a temporary change, 4873, to Procedure 1-9101-S-06, Revision 1, in order to increase the shutdown margin from greater than or equal to 2000 pcm to greater than or equal to 5000 pcm and to provide for DRPI and demand position indication during testing. This monitoring involved assuring ±12 step agreement during and after rod motion or else stopping rod motion and investigating prior to resumption of testing.

The inspectors understand the rationale and precautions taken by the licensee to support the interpretation that the mechanism timing tests are a part of rod drop time measurements, however, the inspectors expressed concern with the validity of invoking special test exception 3.10.5 for mechanism timing tests.

On November 26, 1986, Advance Change 3 was written to Procedure 1-9101-S-06, Revision 1, in order to initially withdraw a given rod group to 6 steps prior to mechanism timing tests and to leave each group at 6 steps following the mechanism timing test for that group. This was consistent with generic Westinghouse guidance to preclude driving rods into the 0 step position and possibly damaging them. Although this change resulted in more than one bank fully withdrawn (in fact by the completion of the test all banks would have been withdrawn to 6 steps) the procedure preparer and reviewer responsible for technical review and safety evaluation did not consider that special test exception 3.10.5 could be implemented for this procedure. They stated that this consideration was based on the fact that special test exception 3.10.5 was for rod drop time measurement testing based on the need to de-energize DRPI during rod drop in order to obtain meaningful data. These personnel stated that they were unaware that the mechanism timing tests were to be performed with DRPI inoperable and consequently did not address this issue on the safety evaluations written to support the aforementioned change. The personnel involved in the interpretation to invoke special test exception 3.10.5 for mechanism timing tests were not sufficiently familiar with the procedural requirements of Procedure 1-9101-S-06, Revision 1, change 3, to understand that it would result in more than one bank of control or shutdown rods being withdrawn from fully inserted contrary to Technical Specification 3.10.5.

Interviews with the Shift Foreman and Shift Test Coordinator reflected that although they were familiar with the test and had been briefed and received turnover related to the test, neither had sufficiently read the procedure to understand that it would result in more than one bank of rods being withdrawn from the fully inserted position.

Interviews with the lead test engineer reflected that he was aware of the test interpretation to invoke special test exception 3.10.5 and was aware of the procedural requirements that would result in more than one bank of rods being withdrawn to 6 steps. He, however, erroneously considered that "fully inserted" meant "no more than 6 steps withdrawn" since generic Westinghouse guidance recommended performing the test in this fashion.

As soon as more than one bank was withdrawn to 6 steps the Shift Test Coordinator immediately recognized the situation as being contrary to Technical Specification 3.10.5 and conveyed this to the Senior Control Operator, who immediately opened the reactor trip breakers pursuant to the action statement for Technical Specification special test exception 3.10.5.

The inspector considers this issue to be licensee identified pursuant to 10 CFR 2, Appendix C. NRC will review during a future inspection licensee establishment and implementation of corrective action.

8. Review Of December 5, 1986 SI Actuation

The inspector reviewed the safety injection (SI) actuation reported to the NRC on December 5, 1986, in Licensee Event Report (LER) 86-004. The summary of the event is as follows. On November 7, 1986, inverters S-II and S-IV were deenergized for a maintenance outage by operations personnel. The removal from service of both of the inverters at the same time resulted in deenergization of both instrument buses II and IV and Power Instrument Cabinets (PIC) 2 and 4. This removed power from two high 1 containment pressure bistables. An SI is initiated on two of three high containment pressure signals therefore the de-energization of two PICs at the same time caused an inadvertent SI signal. No fuel was in the vessel at the time of the event and no water was injected in the vessel since safety systems were locked out.

Plant Incident Report (PIR) 86-043, issued December 3, 1986, indicated that after the modification work to the inverters was originally scheduled that it was subsequently decided that work would proceed on only one inverter at a time, but this fact was not communicated to the operators. Interviews with plant personnel indicate that at a planning meeting held on the morning of November 7, 1986, an operations representative raised a concern that the work should not be done on both inverters at the same time. The management representative indicated that he agreed with this recommendation. The decision was not communicated to the shift personnel and the test plan of the day was not revised. Shift operations personnel stated that a note was left on the test plan of the day indicating that both inverters would be worked at the same time.

The inspector noted that neither PIR 86-043 nor LER 86-004 discussed the failure to communicate the decision to work one inverter at a time as a root cause and corrective actions proposed in the reports did not address the correction of this problem. The PIR attributed the root cause to a personnel error on failure to adequately review or understand system operation. It is not clear that the operations representative knew of the potential problem with system operation or made the recommendation based on a conservative approach, however, the failure to communicate the decision and update the test plan of the day is considered by the inspector to be the root cause of the event.

The licensee stated that actions had been taken in November, 1986 to assure that communication between the groups involved in startup activities was upgraded. This action included issuance of a memorandum from the Power Ascension Test Director to the power ascension staff discussing the responsibilities of power ascension personnel and a memorandum to Shift Test Engineers on their responsibilities. Additional plant events will be reviewed to determine if corrective actions have improved communications and to determine if other events have resulted due to miscommunication or failure to update administrative control documents to reflect current management decisions on plant operations.

PIR 86-043 indicated that during the SI actuation, a residual heat removal (RHR) pump ran for two and one-half minutes with the suction and discharge closed. Significant Operational Occurrence Report (SOOR) 86-005, which documents the four hour report to the NRC does not indicate that this information was reported to the NRC. The block which states, "Anything unusual or not understood?" was marked "No." The block which states "Did all systems function as required?" was marked "No," however, only an emergency diesel generator exhaust fan which did not start was cited as a problem. No mention of the RHR pump problem was made in SOOR 86-005 or LER 86-004. The inspectors consider that if the plant had been an operating plant at the time of this event, reporting this improper operation of the RHR pump as unusual would have been required. The inspector reviewed the documentation of the testing performed to assure that the RHR pump was not damaged during the event. The A train RHR pump was started on November 9, 1986, and vibration readings were taken. Vibration readings were less than baseline readings. Engineering Surveillance Test EST-205, RHR System Flow Test, was satisfactorily completed on November 24, 1986 while in Mode 6. OST-1108, RHR Pump Operability, was satisfactorily completed on December 10, 1986, while in Mode 5. No discrepancies were identified in the testing. The inspector also noted that an Advance Change Form was issued to Administrative Procedure AP-020, Clearance Procedure, on November 24, 1986, to require that tagging be sequenced to avoid improper lineups during the tagging process. No discrepancies were identified. The inspector discussed the documentation of the testing with the licensee and recommended that additional emphasis be placed on maintaining the results of tests proving operability of safety-related systems in a retrievable form since some of the test information was in a startup test log.

The inspector also noted during review of PIR 86-043 that a previous event, documented in PIR 86-19, involved deenergization of a PIC which caused an inadvertent start of Emergency Service Water pump 1A. A part of the corrective action for this event includes a review of the adequacy of information provided to operators on loss of power to plant buses. The corrective action for the event is still open on the licensee's tracking system. Discussion of this previous event was not provided in LER 86-004.

PIR 86-043 also indicated that three hours later as the inverter clearance procedure was continuing, a containment spray actuation bistable tripped on a high 3 containment pressure signal. PIR 86-043 indicated that there was no explanation as to why the signal was received at the time of the report. The licensee stated that the reason for the bistable trip was still being evaluated. There was no mention of this problem in LER 86-004.

The inspector discussed the evaluation and review process for writing an LER with the licensee. It appeared that Plant Incident Reports had been written independently of the LER input in the past. The Plant Incident Reports, which provide indepth evaluation of events, were not routinely used by the group which wrote the LERs. Licensee representatives stated that the Plant Incident Report was for internal use and provided more information than was necessary for the LER. The licensee also stated that the Plant Review Board had determined during the past month that LERs were not adequate and had directed that several LERs be rewritten. In addition, the licensee stated that plant management had directed that the Plant Incident Report be utilized in the writing of the LERs. The inspector indicated to the licensee that reports to the NRC on events should provide all pertinent information and, in particular, should document any unusual operation or malfunction of safety related equipment. The inspector also indicated that the licensee should provide updated reports where unusual operation or malfunctions of safety related equipment was discovered during a subsequent evaluation of an event.