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

Report No.: 50-261/91-01

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

Docket No.: 50-261 License No.: DPR-23

Facility Name: H. B. Robinson

Inspection Conducted: January 11 - February 15, 1991

Lead Inspector: for L. W. Garner, Senior Resident Inspector 3/5/91 Date Signed

Other Inspectors: R. E. Carroll
M. M. Glasman
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Approved by: for H. O. Christensen, Chief 3/5/91 Date Signed
Reactor Projects Branch 1
Division of Reactor Projects

SUMMARY

Scope:

This routine, announced inspection was conducted in the areas of operational safety verification, installation and testing of modifications, surveillance observation, maintenance observation, onsite review committee, and followup.

Results:

A violation with two examples was identified for failure to accomplish activities affecting quality in accordance with procedures or drawings. The first example involved maintenance technicians' failure to perform modification acceptance testing as documented, which resulted in the improper declaration of modification operability (paragraph 3). The second example involved an incorrect size fuse being installed in the A SI pump control circuit other than that shown on the applicable drawing (paragraph 5).

A violation was identified for inadequate modification acceptance tests being specified for component functional verification (paragraph 3).

A violation was identified involving an inadequate procedure change to test the main steam line isolation function. This indicated a weakness in the preparation and technical review process associated with logic testing procedures (paragraph 4).

A non-cited violation was identified for failure of a worker to be dressed in accordance with radiation work permit requirements (paragraph 2).

ASME Code relief was granted to operate cycle 14 with engineered repairs to service water containment penetrations and piping inside containment (paragraph 2).

Preliminary closeout inspections of the containment indicated that the cleanup was not being performed in a thorough, systematic manner (paragraph 2).

Two service water system spills in containment and the auxiliary building were apparently caused by unanticipated valve seat movement (paragraph 2).

The recovery evolution for an unlatched control rod was well planned and executed (paragraph 2).

Two drawing discrepancies were identified. A reactor protection system drawing incorrectly identified the source of power to the reactor trip breaker circuit. A safeguards logic diagram did not indicate that an automatic containment spray initiation signal would also initiate a safety injection signal (paragraph 2).

A green liquescent substance originating from Machine Tool wiring was discovered on contactors inside class 1E motor control centers. This was identified as the probable cause of two valves failing to operate properly (paragraph 5).

The licensee is developing a fuse schedule as part of the development of an overall fuse control program (paragraph 5).

A commitment was not met to develop a Plant Specific Technical Guideline by September 28, 1990, in that the basis for some setpoints were not established (paragraph 7).

REPORT DETAILS

1. Persons Contacted

*R. Barnett, Manager, Outages and Modifications
C. Baucom, Shift Outage Manager, Outages and Modifications
*D. Bauer, Regulatory Compliance Coordinator, Regulatory Compliance
J. Benjamin, Shift Outage Manager, Outages and Modifications
C. Bethea, Manager, Training
*W. Biggs, Manager, Nuclear Engineering Department Site Unit
*S. Billings, Technical Aide, Regulatory Compliance
*R. Chambers, Manager, Operations
T. Cleary, Manager - Balance of Plant Systems and Reactor Engineering, Technical Support
*D. Crook, Senior Specialist, Regulatory Compliance
*J. Curley, Manager, Environmental and Radiation Control
*C. Dietz, Manager, Robinson Nuclear Project
*D. Dixon, Manager, Control and Administration
J. Eaddy, Manager, Environmental and Radiation Support
F. Eckert, Manager, Planning and Scheduling, Outages and Modifications
S. Farmer, Manager - Engineering Programs, Technical Support
R. Femal, Shift Supervisor, Operations
B. Harward, Manager - Mechanical Systems, Technical Support
*J. Kloosterman, Manager, Regulatory Compliance
D. Knight, Shift Supervisor, Operations
*D. Labelle, Project Engineer, Nuclear Assessment
E. Lee, Shift Outage Manager, Outages and Modifications
*A. McCauley, Manager - Electrical Systems, Technical Support
R. Moore, Shift Supervisor, Operations
D. Nelson, Shift Outage Manager, Outages and Modifications
*M. Page, Manager, Technical Support
D. Seagle, Shift Supervisor, Operations
*J. Sheppard, Plant General Manager
*R. Smith, Manager, Maintenance
*D. Stadler, Onsite Licensing Engineer, Nuclear Licensing
R. Steele, Shift Supervisor, Operations
*D. Stepps, Senior Engineer, Nuclear Engineering Department Site Unit
*G. Walters, Operating Event Followup Coordinator, Regulatory Compliance
D. Winters, Shift Supervisor, Operations
H. Young, Manager, Quality Control

Other licensee employees contacted included technicians, operators, mechanics, security force members, and office personnel.

*Attended exit interview on February 25, 1991.

H. Christensen, Section Chief, Division of Reactor Projects, Region II was on site January 22-24, 1991, to meet with the resident inspectors and plant management.

Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Operational Safety Verification (71707)

The inspectors evaluated licensee activities to confirm that the facility was being operated safely and in conformance with regulatory requirements. These activities were confirmed by direct observation, facility tours, interviews and discussions with licensee personnel and management, verification of safety system status, and review of facility records.

To verify equipment operability and compliance with TS, the inspectors reviewed Operations' records, data sheets, instrument traces, and records of equipment malfunctions. Through work observations and discussions with Operations Staff members, the inspectors verified the staff was knowledgeable of plant conditions, cognizant of in-progress surveillance and maintenance activities, and aware of inoperable equipment status. The inspectors reviewed component status and safety-related parameters to verify conformance with TS. The inspectors observed that proper control room staffing existed, access to the control room was controlled, and Operations personnel carried out their assigned duties in an effective manner.

Plant tours and perimeter walkdowns were conducted to verify equipment operability, assess the general condition of plant equipment, and to verify that radiological controls, fire protection controls, physical protection controls, and equipment tagging procedures were properly implemented.

Unlatched Control Rod

On January 29, 1991, during performance of EST-048, Control Rod Drop Test, RCCA C-07 exhibited an abnormal rod drop trace and time. The initial belief was that some equipment malfunction, such as a loose monitoring lead connection, had caused the abnormal indications. Repeat testing on the next day produced similar results (i.e., the trace was not a smooth curve and the rod took approximately one second longer to fall than anticipated). On January 31, 1991, the inspectors witnessed SP-1012, Control Rod Drive Mechanism C-07 Testing, which verified that the C-07 drive shaft was uncoupled from its RCCA. This was based upon the rod lift, moveable gripper and stationary gripper coil current traces, as well as sound traces which demonstrated that the C-07 drive shaft reached its maximum and minimum position three steps before three other rods reached their respective maximum and minimum positions. The C-07 lift coil current also revealed that the lift coil consistently moved its drive shaft one step quicker (by approximately 20 milliseconds) than other lift coils raised their drive shafts one step (i.e., the C-07 lift coil only had to move the weight of a drive shaft, not a drive shaft and an RCCA).

Recovery of the unlatched control rod involved removal of the reactor vessel head, as found inspection of C-07, and video camera inspection of the associated guide tube and RCCA. The inspectors witnessed performance of SP-1016, Testing And Latching; Inspection And Unlatching Of The RCCA At Core Location C-07, which confirmed by weighing that the C-07 drive shaft was not attached to its associated RCCA. Subsequent testing revealed that the drive shaft could be latched to the RCCA. A visual inspection of the drive shaft revealed minor scratches and denting at the latching end of the drive shaft. Video camera inspection of the RCCA hub revealed only superficial damage. There was not a condition found which could explain the failure of the drive shaft to be latched to the RCCA. Video camera inspection of the guide tube identified that it had been struck at several locations by the drive shaft during rod drop testing. The top of one opening where the RCCA rodlets moves through the guide tube was determined to be bent inwards. Based upon the observed damage, Westinghouse recommended that the guide tube be replaced. A new drive shaft and guide tube were installed. The RCCA was inspected by video camera and partially lifted to verify freedom of movement. Based upon these results, the RCCA was determined to be acceptable for continued service.

Prior to reactor vessel head installation, special verifications were performed of each control rod to ensure by visual inspection and "go, no-go" gaging that the drive shafts were set inside the RCCA hubs and the latching buttons were properly engaged. The inspectors noted that the recovery evolution was well planned and executed.

<u>Inadverent Removal of Source Assembly</u>

On February 10, 1991, while moving the upper internals package for C-07 recovery evolutions, the lift was terminated when the control room operator observed that source range monitor NI-31 count rate rapidly decreased from 100 cpm to 20 cpm. Visual inspection revealed four rodlets hanging from under the upper internals package. These rodlets were determined to be an antimony-beryllium secondary source assembly. At the time of discovery, the bottom of the upper internals package was approximately 2 to 3 feet above the reactor vessel flange. The inspectors witnessed successful performance of SP-1015, Secondary Source Inspection And Recovery. The SP provided instructions for lifting the upper internals package sufficiently high enough to allow movement across the reactor flange area with the 14 foot long source assembly attached and subsequent removal of the source. Movement across and positioning the source above the refueling cavity floor was monitored by underwater cameras. Once positioned a few inches above the floor, a long rod was used to reach inside the guide tube and lightly tap the top of the source assembly. The source assembly, weighing approximately 27 pounds, fell uneventfully onto the cavity floor. The source assembly was subsequently removed to the SFP for disposal. The inspectors verified that ALARA and radiation protection considerations were appropriately considered during this evolution.

Root cause investigation attributed this event to an inadequate technical review. The source assembly was installed this RO in a different core location, H2, than that previously utilized. This particular location does not have a flow vane installed in the top core plate as previous locations did. The flow vane presses down onto the source assembly, thereby, keeping the assembly in place. Without a flow vane installed, the core differential pressure was sufficient to allow the light weight source assembly to float up and wedge approximately eight inches inside the upper internals package. Corrective actions to preclude future occurrences of positioning core components into undesirable locations are under development.

As a result of not being able to reload this source into the core, there is no irradiated source assembly installed in the core. However, the NI-31 and NI-32 count rates, approximately 20 cpm due to the presence of irradiated fuel, are sufficient to allow a safe restart.

ASME Code Relief Request - SW Piping

On January 6, 1991, MIC was identified in the six inch diameter, schedule 40, 316L stainless steel weld joints in the SW supply and return piping of containment fan cooler HVH-4. MIC indications were subsequently observed in 11 of 16 HVH-4 piping weld joints radiographically examined. The affected HVH-4 piping contained a total of 53 weld joints. One weld joint was removed and taken to the HE & EC for analysis; the HE & EC confirmed the presence of wall thinning due to MIC. The MIC initiation location was along the base metal/weld metal interface and the weld. This location was different from the MIC previously observed in the 304L stainless steel HVH SW return and supply piping, in that, the 304L MIC had initiated in the weld joint heat affected zone adjacent to the weld. During RO 12, all the stainless steel HVH SW supply and return lines inside the CV were replaced with AL6XN material except for the 316L piping discussed above and inside the containment penetrations. The HVH-4 SW piping traversing under the refueling canal had been replaced in 1985 with 316L material. All five 316L HVH-4 weld joints radiographically examined in 1988 showed no MIC indications.

Radiographic examinations of the eight containment penetrations (a supply and return penetration for each of the 4 containment fan coolers) identified 4 penetrations with MIC. The eight containment penetrations had a 316L stainless steel liner installed in 1985 inside the 304L penetration piping. The 304L penetration piping was fillet welded to the liner and the 304L SW piping to the HVH units was then inserted over a portion of the liner and fillet welded to the liner. During RO 12, the liners were cut, the 304L piping from the CV side of the penetrations to the HVH units was removed and replaced with AL6XN material. The AL6XN piping was inserted over the liner and fillet welded to it. This resulted in the stainless steel liner being in contact with SW and having heat affected zones acting as a containment boundary.

On January 16, 1991, the licensee requested an ASME code relief to allow operation with temporary, non-code, engineered repairs to the above described piping due to material availability and the long lead time required for penetration repair technique development. The engineered repair consists of welded sleeves over all the 316L HVH-4 weld joints which were not code repaired and welded sleeves over the piping of 4 containment penetrations which contained MIC indications. The relief request demonstrated that the unit could operate safely with the non-code repairs. The licensee committed (in the request) to replace the non-code repaired 316L HVH-4 piping during RO 14 and submit to the NRC, a plan and schedule for permanent repair of the containment penetrations by September 30, 1991. After review, the NRC granted the relief request on January 23, 1991. When the outage was extended as a result of an unlatched control rod, the inspectors verified that delivery dates associated with the AL6XN elbows made it impractical to make permanent code repairs to the HVH-4 during this RO.

<u>SW Spills Into Containment and Auxiliary Building</u>

On January 8, 1991, at 9:00 p.m., "significant leakage" was identified coming from an open section of HVH-4 piping, and started flooding the first level of the CV. This open piping was caused by the removal of a section of piping for MIC analysis. As operations was attempting to determine the source of the water, the leak stopped with no apparent actions having been initiated to terminate it (i.e., valve manipulation/source isolation). Upon evaluation, it was determined that approximately 12,000 gallons had discharged into the CV sump. The SW system and the HVH-4 unit had been isolated with proper clearances and drained prior to the piping removal. An investigation and ACR 91-014 were initiated the next day to determine the source and/or cause of the leak. The system had no unisolated potential leakage paths available that could have accounted for this volume of water. A subsequent SW leak (see below) revealed the probable flow path for this spill.

On January 17, 1991, during a SW system line-up for a hydrostatic test, approximately 1600 gallons of SW leaked into the CV and Auxiliary Building hallway. This leak occurred when the flange joint downstream of butterfly valve V6-33E was separated, allowing the valve seat to shift out of the valve. This allowed water to flow by the disc and pressurize the piping downstream. When the downstream piping associated with butterfly valve V6-33D was subsequently opened, a leak path was created, allowing the water to flow onto the Auxiliary Building floor. Additionally, there was apparently a vent and drain valve open in the CV in preparation for the hydrostatic test; thus allowing leakage into the CV. Operations subsequently isolated the leak and initiated ACR 91-040 to determine root cause.

The seat movement associated with valve V6-33E evidently was the root cause of both the January 8 and 17, spills. In the January 8 spill, the V6-33E flange joint was partially opened at a time which corresponds to spill initiation. The licensee believes that the seat moved during this event allowing water to flow around the disc and out the open section of piping. All the other HVH unit supply SW valves, as well as other SW system valves, are Allis Chalmers Streamseal resilient seated butterfly valves. These valves have quickly changeable seats which are positioned by the compressive force of the mating flanges. The phenomenon of the seat moving, due to water pressure on the upstream side of the seat when the downstream flange was unbolted, was unexpected. The licensee is performing (through the ACR process) root cause verification, as well as the scope of and the need for procedural controls to ensure clearance boundary adequacy in the future. The inspectors will review the corrective actions adequacy through routine ACR monitoring and evaluation.

Contamination Protection Practices

On February 10, 1991, the inspectors observed an individual inside the CV who was not dressed in accordance with the applicable RWP requirements. The individual was observed wearing a skull cap with her hair exposed; the applicable RWP, 90-637, required a cloth hood. This condition was reported to an onshift HP technician inside the CV who had the individual correct her dress. In addition, another worker was observed inside the CV without his gloves taped to his PCs, which is considered a poor work practice. This was also reported to an HP technician who had the individual tape the gloves. These observations were later discussed with the E & RC Manager who subsequently sent a memo to the HP Foremen re-emphasizing the need for HP personnel to set and enforce high standards. An NCV was issued in IR 90-18 involving failure of a laboratory technician to dress in accordance with an RWP. However, there is a dissimilarity between the 90-18 item and the above RWP violation, in that the laboratory technician failed to recognize that he needed protective clothing, whereas, the RWP violation involved improper dress. The corrective actions taken by the E & RC Manager before the end of the inspection period were deemed appropriate. This violation is not being cited because the criteria specified in section V.A of the NRC Enforcement Policy were satisfied. This item is a NCV: Failure To Follow The Provisions Of A RWP As Required By PLP-016, 91-01-01.

CV Cleanup

On January 31, 1991, while performing a general area inspection of the CV, the inspectors observed debris under two containment fan cooler units. The debris included a plastic bottle, two rolls of duct tape, discarded gloves, a sign, metal tags, and wads of paper and tape. The other two containment fan coolers were not examined. The inspectors observed isolated pieces of trash on, under, and behind various pieces of equipment, panels, and supports. Upon exiting the CV, the inspectors discussed the conditions with an SRO who had made a similar tour earlier that day. The SRO had also observed the above conditions. These observations were significant, in that, efforts had been in progress for a minimum of three days to clean up the CV in preparation for restart. The daily outage schedule for January 30 to January 31, 1991, listed the final CV walkdown prior to 200 degrees and closeout per PLP-006, Containment Vessel Inspection/Closeout, was to be at 2:00 p.m. on January 31. The preliminary walkdown by the SRO on that day revealed that the final CV closeout per PLP-006 was not possible. The resident inspectors also noted that a partial CV walkdown by the licensee on January 29, 1991, which generated a list of 45 items to be addressed prior to CV closeout, had not identified the debris under the containment fan coolers. The inspectors discussed their observations with the Plant General Manager concerning CV cleanliness. The inspectors were concerned that these observations, along with those documented in IR 90-05 and 90-12, indicated that the cleanup inside the CV had not been approached in a thorough and systematic manner.

Circuit Breaker Identification Aids

On January 18, 1991, the inspectors observed that outdated circuit breaker lists were posted inside instrument buss panels 7A and 9A. The circuit breaker lists provides information as to the function associated with each circuit breaker located in a panel. Subsequent review by both the inspector and the licensee revealed that the problem also existed in other instrument buss and power panels. The method used to maintain current circuit breaker lists in the panels involved a designated operations technician receiving a controlled revision to the applicable procedure containing the list. He is then responsible for placement of the revised list inside the panel. However, in May 1990, the technician, was inadvertantly deleted from distribution for these revisions. At the end of the report period, the current lists had been placed in the panels and the procedure revision distribution list had been changed to include the operations technician for distribution of future revisions.

One non-cited violation was identified.

3. Installation And Testing Of Modifications (37828)

Modification M-1016, Electrical Penetration Replacement Testing

During performance of EST-048, Control Rod Drop Test (Refueling Outage), revision 6, on January 29, 1991, the RPI for RCCA P-6 in control bank B failed to increase in response to control bank B withdrawal. However, the RPI for RCCA D-10 in control bank C did increase in response to control bank B withdrawal. Similarly, when control bank C was withdrawn, RCCA D-10 RPI failed to increase while RCCA P-6 RPI indication increased. At that time, EST-048 was exited, all control rods were fully inserted, the reactor trip breakers were opened, and the rod drive cabinet fuses were reinstalled. ACR 91-060 was generated to document and investigate this anomaly.

Upon investigation, it was determined that the electrical penetration through which these RPI cables traverse was changed from Penetration C-2 to E-1 during implementation of modification M-1016, Electrical Penetration Replacement. The modification had been declared operable on January 22, 1991. Apparently, during or after modification implementation the RPI cables for P-6 and D-10 (cable numbers C2078BN and C2079BC, respectively) were "rolled" or switched. This situation was not detected during modification implementation, QC verification, or modification acceptance testing.

As a result of the modification being declared operable without detection of the problem, the adequacy of the acceptance tests specified and performed was evaluated. In the case of the RPI cables, the acceptance test specified was the performance of loop calibration procedure LP-551, Rod Position Indication System, revision 3. The test was to be performed in 45 relocated cables. After the rolled leads were corrected, LP-551 was not performed as expected. Upon further investigation it was determined that LP-551 had not been performed as required for any of the 45 RPI cables prior to the modification being declared operable. The maintenance technicians had initialed the functional test signature blocks as having been performed, when evidently, the only test performed was a resistance check of each RPI's cable. The resistance check could not and did not identify the rolled leads. Additionally, the functional tests (LP-251, Radiation Area Monitors RMS R1-R8) specified for radiation monitors R-2 and R-7 were signed as having been completed. However, this procedure had been deleted approximately two months earlier and replaced by test procedure OST-924, Radiation Monitoring System, neither of which was performed for the acceptance test. The testing which the technicians performed cannot be verified. In addition, there are other examples within the modification where the testing performed was not the specific testing specified. The failure of the maintenance technicians to conduct the functional testing specified in the modification is the first example of a violation: Activities Affecting Quality Were Not Performed In accordance With Procedures And Drawings, 91-01-02.

During the review of the testing conducted versus the testing specified to be performed, it was identified that some functional tests specified in the modification were not adequate to test the components/cables which were affected by the penetration replacements. Examples of this included a specified resistance check as a functional test on approximately 60 temperature elements. The resistance checks performed only verified the equipment was connected; the tests did not confirm that the resistance was in fact, at the instrument it should be. Additionally, LP-551, which was the functional test specified for the RPIs, was inadequate to functionally test individual RPIs. As such, if the rolled leads were not identified during performance of a test (EST-048) unrelated to the modification, these RPI would not have been functionally tested. There were additional tests specified in the modification, the adequacy of which were questionable. Examples of these questionable tests included PIC-009, Current/Pressure (I/P) Transducer, and PIC-401, Valve Positioner, which were specified as the functional tests for three valves; and OP-202, Safety Injection and Containment Vessel Spray System, which only performs a valve line-up for valve HCV-936. The failure to adequately establish tests is a violation: Modification M-1016 Acceptance Tests were Inadequate, 90-01-03.

There are two concerns associated with these violations. The first relates to the inadequate acceptance tests, in that there appeared to be inadequate reviews performed on the tests' adequacy during the modification review and approval process. Modification acceptance testing adequacy has been a previous identified concern and this problem underscores the need for additional efforts in this area. The second concern relates to the oversight provided during component/cable functional testing, in that, the modification was declared operable without the functional tests specified being performed. This testing was performed over a period of several weeks, thus allowing numerous occasions for the identification of the tests not being performed as specified. More interactive oversight may be warranted during modification development, implementation, and testing.

Two violations were identified.

4. Monthly Surveillance Observation (61726)

The inspectors observed certain safety-related surveillance activities on systems and components to ascertain that these activities were conducted in accordance with license requirements. For the surveillance test procedures listed below, the inspectors determined that precautions and LCOs were adhered to, the required administrative approvals and tagouts were obtained prior to test initiation, testing was accomplished by qualified personnel in accordance with an approved test procedure, test instrumentation was properly calibrated, the tests were completed at the required frequency, and that the tests conformed to TS requirements.

Upon test completion, the inspectors verified the recorded test data was complete, accurate, and met TS requirements; test discrepancies were properly documented and rectified; and that the systems were properly returned to service. Specifically, the inspectors witnessed/reviewed portions of the following test activities:

EST-004	Isolation Valve Seal Water
EST-006	Containment Spray Nozzles
EST-049	Rod Drive Mechanism Operation Testing (Refueling Outage)
EST-058	SI-890A And 890B Check Valve Test
OST-163	Safety Injection Test And Emergency Diesel Generator Auto Start On Loss Of Power And Safety Injection And Emergency Diesel Trips Defeat
OST-351	Containment Spray System
SP-1002	RHR Pump Flow Test
SP-1007	RHR Pump Flow Test
SP-1010	Service Water Flow Test
SP-1012	Control Rod Drive Mechanism C-07 Testing

OST-351

On January 17, 1991, the inspectors witnessed the performance of OST-351, Containment Spray System, revision 9. The test was terminated when certain relays were not energized as required by OST steps 7.2.13 through 7.2.16. A review of Safeguards System drawings CP-380-5379-3233, 3235, and CWD B-190628 sheets 141, 144, and 147, indicated that the relays should not have been energized. A previously performed step, 7.2.9, had returned the bistables, which were tripped to cause a containment spray initiation, to their normal position. This action reset the indication signal and removed the power from the relay coils which were to be verified as energized in steps 7.2.13 through 7.2.16. It was also observed that steps 7.2.13, 7.2.14, and 7.2.15 referred to the relays as SX relays on panels AA, KA, and MA, where as the CWD sheets 141, 144, and 147 referred to these relays as SX1, SX2, and SX2 on panels AA, KA, and MA, respectively. Review of OST-351, revisions 6 and 7, completed May 28, 1987, and November 15, 1988, respectively, as well as revision 8 (never performed) revealed these earlier revisions also contained the step to reset the bistables to normal prior to performing the relay verification steps. Thus, on at least two prior occasions, the procedure steps were improperly signed as having been satisfactorily completed. Apparently, personnel preparing the procedure knew that the steps were to be performed in response to the containment spray initiation signal and not in the sequence specified in the procedure (i.e., after the initiation signal was reset. Personnel implementing the procedure had performed the steps as intended, not as written. The fact that on January 17, 1991, I & C technicians did not sign OST-351 steps 7.2.13 through 7.2.16 as being satisfactorily completed, indicated that in the Maintenance unit an evolving awareness of what constitutes procedure adherence is occurring. At the same time, however, a licensed operator signed that "both containment spray pumps START" and selected valves "have OPENED" and "have CLOSED" after the containment spray initiation signal was reset. Since the steps did not require verification that the pumps remain running or the valves remain opened or closed; the operator had actually acknowledged that the actions occurred as a result of the initiation signal reset verses the initiation signal. The failure by the operator to recognize that changes of state of equipment during testing should be attributed to the step immediately preceding the change of state, unless otherwise specified, was identified as a weakness in procedure adherence. This was discussed with the Operations Manager.

On January 18, 1991, OST-351 revision 10, was issued to correct the above problem (i.e., the actions which occur as a result of the initiation signal are to be verified prior to resetting the initiation signal). Revision 10 incorporated additional steps to correct another deficiency (i.e., the B train MSIV closing solenoid circuits were not being completely tested). To address this oversight, revision 10 included steps to verify that relays SX2, SX1 and SX1 on respective panels JB, FB, and DB energize. However, with the RTGB control switch in the shut position (the condition it would most likely be in due to these steps routinely being performed when the MSIVs are under clearance) these relays are already energized and remain energized. This was recognized by the onshift personnel preparing to perform the new revision. Revision 10 was satisfactorily performed on January 19, 1991, with the notation that relays on panels JB, FB, and DB are always energized with the control switches in the shut position. Abnormal Condition Report ACR 91-035 was issued to address the adequacy of OST-351 to test the MSIV isolation logic. Revision 11 was issued and was successfully performed on January 26, 1991, to completely test the MSIV logic. The failure to provide adequate steps in revision 10 to test the MSIV logic indicated a weakness in the preparation and technical review process involved with logic test procedures. Discussion with the revision 10 procedure preparer revealed that he had only received on-the-job training involving preparation of, or changes to logic test procedures. The inadequacy of OST-351 revision 10 to completely test the MSIV closure logic is a violation: OST-351, Revision 10 Was Inadequate In That It Did Not Completely Test The MSIV Logic, 91-01-04.

Another example of a recently issued inadequate procedure change was temporary change no. 4092 issued to SPP-011, Removal And Restoration Of SI Actuation. The temporary change dated January 17,1991, incorporated steps for a continuity check to be used to verify proper wiring restoration. The steps would not work as written because an indicating light circuit was in parallel to the circuit being verified. Another temporary change dated January 26, 1991, to SPP-011 was issued and successfully performed to verify continuity of the restored wiring. Revision 5 to SPP-011 was issued on February 16, 1991, to permanently incorporate this change into the procedure.

Service Water System Flow Test

On January 29, 1991, a SW system flow test was conducted per SP-1010, Service Water Flow Test. The SW system had undergone extensive repairs/refurbishment and this test was performed to confirm adequate system performance. The system mode tested was an accident configuration (i.e., two SW pumps running, turbine building SW loads isolated, and approximately 10,000 gpm circulated through the CCW HXs). The test verified that the minimum required SW flow of 564 gpm to each EDG HX was satisfied. The flows to the EDG HXs were acceptable and exceeded the required 564 gpm with and/or without the SWBPs operating (with the SWBPs operating, the EDG HXs receive less flow). The KYPIPE computer program was used to model system configurations and expected resultant flows and pressures. The KYPIPE predictied flows and pressures corresponded similarly with those measured during the test.

Drawing Deficiencies

During review of the OST-351 deficiencies discussed above, the licensee and the inspectors together identified that logic drawing CP-300 5379-2759, revision 15, did not show that a high high containment pressure containment spray initiation signal would initiate an SI signal if RCS coolant temperature is above the low TAVG setpoint. Safeguard drawings CP-380- 5379-3232, 3233 and 3235 show that the automatic containment spray initiation relays AS1 and AS2 energize relays SL1 and SL2 which energize the safety injection initiation relays SIA1 and SIA2. This is apparently a backup to the high containment pressure SI initiation signal.

The inspectors also identified two other drawing discrepancies. Reactor Protection System drawing CP-380 5379-3244 revision 12, showed the reactor trip contacts in the reactor trip trains A and B being powered from 125 VDC panel A circuit 10 and panel B circuit 9, respectively.

However, drawing CP-380 5379-3243 and 3252 show that the trip contacts are powered from panel A circuit 18 and panel B circuit 18 via train A and B terminal strips 5T7. The licensee has agreed that drawing 3244 is in error and will revise it. Residual Heat Removal System Flow Diagram 5379-1484 revision 19, did not show that the piping to valve RHR-744A, the SI Cold Injection Valve, is reduced from 12 to 10 inches. A 12 X 10 inch reducer is shown upstream of the RHR-744B valve. The licensee is reviewing this drawing to determine if it should be clarified.

One violation was identified.

5. Monthly Maintenance Observation (62703)

The inspectors observed safety-related maintenance activities on systems and components to ascertain that these activities were conducted in accordance with TS, approved procedures, and appropriate industry codes and standards. The inspectors determined that these activities did not violate LCOs and that required redundant components were operable. The inspectors verified that required administrative, material, testing, radiological, and fire prevention controls were adhered to. In particular, the inspectors observed/reviewed the following maintenance activities:

SP-1008	Removing Green Oily Resin And Replacing Power Wiring In MCCs 5,6, 9, & 10
SP-1015	Secondary Source Inspection And Recovery
SP-1016	Testing And Latching, Inspection And Unlatching Of The RCCA At Core Location C-07
SPP-011	Removal And Restoration Of SI Actuation
WR/JO 91-ACDK1	Reactor Head Stud Cleaning

Machine Tool Wire

On January 4, 1991, the B main feedwater stop valve V2-6B, failed to close. Upon investigation poor continuity readings were measured on one phase of the MCC closing contactor and a clear covering, like nail polish, was popped off the contact surface. The valve subsequently cycled properly. A similar incident involving the need to clean an unidentified substance from contactors associated with V2-35B, radiation monitor sample for HVH-2 return isolation valve, had occurred during the preceding week.

In neither instance was the removed material retrieved for analysis. Inspections revealed a green liquid gel in the contactor housings, but not on the contact surfaces. Examination of other 208 and 480V MCCs revealed that most compartments exhibited green liquid migration out of the power conducting internal wiring of the MCCs.

Initial evaluation revealed that the green liquid appeared to be a vegetable oil plasticizer used in the PVC covered wire. The wire was black in color and marked as machine tool wire - 105 degrees C. Subsequent analysis indicated that the green liquescent material is a conductor when in a liquid/gel form but may be a conductor or insulator when dried; dependent upon the amount of copper oxide salts dissolved in the material. The liquid may range in color from light green (almost clear in thin films) to dark green, also depending on the amount of dissolved copper oxide salts. The licensee determined that the above mentioned valve failures were most likely due to the plasticizer migrating onto one or more of the contactor contacts.

The licensee's inspection of Class 1E MCC compartments revealed the presence of the green material in most compartments. The only use identified for machine tool wire was to connect the breaker to the contactors. The effected MCC compartments are size 1 compartments manufactured by Westinghouse around 1962. The wire is commercial grade AWG #12 wire supplied under industry standards in effect at that time. Westinghouse obtained wiring from several different vendors during the early 1960s. Records review to date has not identified the manufacturer or manufacturers of the machine tool wire. In the late 1960s, Westinghouse discontinued use of this wire and began use of wire with a different insulating material.

The licensee developed and implemented SP-1005 to replace the machine tool wire with surprenant wire and cable type CL-1251 XLPE 600V wire and to clean the contactors in 111 compartments of MCCs 5, 6, 9, and 10. Since the green material was also observed in non-safety related MCCs, plans were being developed to replace the machine tool wire and clean these affected compartments during RO 14. The inspectors verified via examination of all compartments on MCC 6 and 9, that the wire was not used in other applications. The inspectors also looked inside reactor protection and safeguard cabinets and instrument buss and power panels. Again, no other use of the wire was discovered.

Fuse Control

On January 16, 1991, while witnessing performance of OST-163, the inspectors observed that the installed A SI pump control power fuse was a Bussman Type F61C 30 AS fuse. The similar fuse associated with C SI pump was a Bussman F61C 10 AS fuse. Control wiring diagram B-190628 sheets 237, revision 14, and 239, revision 12, required 10 ampere fuses to be installed in the A and C SI pump 125 VDC control circuits respectively. The licensee verified that the fuse installed in the A SI pump circuit was a 30 ampere fuse. Since there were no replacement 10 ampere fuses in stock, the fuse from the C SI pump circuit was placed in the A SI pump circuit. The C SI pump has been offsite for casing repairs since mid-1989. Procedure OST-163 was subsequently successfully performed, thus ensuring the circuit would perform correctly with the lower ampere fuse installed. The inspectors verified that the correct fuse size was installed in six other randomly chosen emergency buss E1 and E2 breaker control circuits. Other discrepancies were not identified. The licensee has subsequently verified that other fuses installed in E1 and E2 breaker control circuits are in accordance with the CWDs. Failure to have the size fuse specified on the CWD installed is a second example of violation 91-01-02.

The inspectors also noted that numerous CWDs did not specify fuse sizes. Furthermore, few safety-related CWDs specify a specific kind or type of fuse. A fuse schedule which provides sizes, acceptable types, and manufacturers for fuse applications did not exist. The licensee has been controlling fuses by replacement-in-kind or by engineering evaluations if a replacement-in-kind fuse was unavailable. However, design information involving what fuse attributes are taken credit for in circuit protection or coordination are not always available. Some circuits such as those associated with Appendix R coordination have design calculations available. The licensee was developing a fuse control program to address these issues. The present status of the licensee's effort include:

- Design guide for fuse selection criteria was in draft

- Identification of calculations which need to be performed to support coordination and/or protection should be completed by Spring 1991. Scheduling of presently identified calculations was in progress

- A fuse schedule which will provide acceptable size, types, and manufacturers for each application was being planned. An initial fuse schedule with known, verified information for most DC fuses and some AC fuses was planned to be issued this fall

The above three items are considered an IFI: Review Fuse Control Program Development And Implementation, 91-01-05.

DC Fuses

Concerns were raised at the Harris Nuclear Plant involving possible misapplication of fuses in DC circuits. The concerns involve applying voltage and interrupting current ratings of either AC fuses to DC circuits or DC fuses to higher than specified DC voltages without consulting the manufacturer. On January 25 and 26, 1991, a licensee field walkdown identified the manufacturer and type of approximately 350 fuses installed in primary 125 VDC circuits.

Engineering calculations were performed to identify the maximum fault current available for each fuse type at the pertinent sections of the 125 VDC distribution system. The fuse types, ratings, and maximum fault currents were submitted to the manufacturers for evaluation. As a result of this process, eleven circuits were identified for which the existing fuses were replaced. The functions associated with these circuits are:

- Batteries A and B DC MCCs undervoltage monitoring (2 circuits)
- PZR safety valve flow monitoring (2 circuits)
- Condensate pump B and Feedwater pumps A and B ERFIS status (3 circuits)
- HVH-1,2,3, and 4 vibration and flow monitoring (4 circuits)

The HVH vibration and flow monitoring circuits had 32 V fuses installed in 125 VDC applications. The other fuses contained in the above circuits were suspect per the vendor as a result of the concerns raised at the Harris Nuclear Plant.

Engineering evaluation EE 91-030 indicated that the inspection, while not a complete inspection, did represent the majority of DC fuses installed. Based upon the limited number of problems identified, EE 91-030 concluded that additional fuse inspections, necessary to complete a DC fuse list, could be performed as plant conditions permit and are not required prior to startup from RO 13.

The licensee presently plans to complete inspection of the installed DC fuses by the end of RO 14. This information will be incorporated into the fuse schedule being developed as one element of the fuse control program discussed above.

MCC Inspection

During Class 1E MCCs 6 and 9 compartment inspection, the inspectors observed various abnormal conditions. These included: V-749B compartment thermal overload reset button was missing and control power transformer was bolted on the same side, thereby allowing the transformer to move on its attachment bracket; SI-845B compartment bucket top latching mechanism was open; V6-33C, V6-33D, V6-33F, V6-35B, V6-35D, V2-16C and V-749B compartments had one or both bucket bottom alignment/attachment screws not engaged; and V2-20A control power circuit contained a Bussman BAF 3 fuse. The inspectors observed that V2-20B compartment contained a

Bussman BAF 1 fuse. The licensee was informed of these conditions. The licensee determined that either the 1 or 3 ampere fuse size was acceptable for the application; however, for consistency, the fuses will be changed so that the same size will be used for similar applications.

A second example of a violation was identified.

6. Onsite Review Committee (40500)

The inspectors evaluated certain activities of the PNSC to determine whether the onsite review functions were conducted in accordance with TS and other regulatory requirements. In particular, the inspectors attended PNSC meetings on January 30 and February 7, 1991, involving plant status review prior to exceeding 200 degrees and a procedure change to allow head lift under existing plant equipment conditions, respectively. It was ascertained that provisions of the TS dealing with membership, review process, frequency, and qualifications were satisfied.

No violations or deviations were identified.

7. Followup (92709, 92701, 92702)

(Closed) LER 88-07, HVH-2 Breaker Failed To Close On Safeguard Sequence During Performance Of Special Test. On February 12, 1988, during performance of a special test while in cold shutdown, containment fan cooler HVH-2 failed to start during the safeguards sequence. Licensee investigation revealed that the breaker, a Westinghouse model DB-50, did not close because of a faulty alarm switch located in the closing circuit of the breaker. Apparently, oxidation buildup on the alarm switch contacts was the root cause of the breaker not closing. The licensee subsequently checked alarm switches on other emergency switchgear supply breakers, and found 11 additional switches that had intermittently high contact resistance readings. These switches were replaced. Interviews with the Manager-Electrical Systems (Technical Support) indicated that the preventative maintenance procedure for DB-50 breakers, PM-402 revision 5, Circuit Breaker Inspection and Testing, requires the alarm switches to be replaced every fifth refueling outage. Furthermore, the inspector was informed that alarm switches which had not been replaced todate will be replaced during the next refueling outage, and PM-402 will be revised accordingly. In addition, the licensee contacted the vendor regarding testing the alarm switches. The vendor indicated that there was not a criteria for such a test, and alarm switch failures were not a widespread problem. A successfully cycling of the breaker, as is done during maintenance and surveillance testing of associated equipment, is the best functional test of the alarm switches. This item is closed.

(Closed) LER 88-08, Operation In Violation Of Technical Specifications Due To Analytic Input Error. This issue involved an error in fuel cycle 12 analytic factor decks used to process in-core detector measurements and to monitor compliance with TS thermal-peaking limits. ANF Corporation notified the licensee (NFS) of the error (assignment of incorrect isotopic data to a reinsert assembly) on March 24, 1988. Flux map reevaluations using corrected analytic factor decks indicated that allowable power level while operating with a 5 percent delta flux target band should have been 99.98 percent instead of the 100.22 percent originally calculated. To ensure peaking factor conformance, TS 3.10.2.2.2 requires the use of the APDMS when power levels exceed the allowable power level. Consequently, subsequent review identified operations during June 29 through August 12, 1987, as being nonconservative (i.e., delta flux target band greater than 3 percent and APDMS was not in use). However, because of inherent conservatism in ANF's power distribution control methodology (PDC-II), subsequent analysis was able to demonstrate that the plant did not operate in an unsafe condition. The inspector considers the additional in-core deck checkout reviews now being conducted by NFS, as well as those actions taken by ANF to strengthen related internal performance and activities to be appropriate.

Somewhat related, the inspector notes that IR 90-23 addressed an ANF LOCA computer code error which was reported by the licensee on October 23, 1990. Consequently, generic ANF concerns will be addressed during the followup of this more recent event under URI 90-23-01. LER 88-08 is considered closed.

(Closed) LER 88-19, Inoperable Containment Fan Coolers Due to Biological Fouling. On September 5, 1988, the licensee notified the NRC of a four-hour non-emergency event due to inoperable containment fan coolers. The licensee found that a significant amount of biological fouling had taken place in the cooling coil tubes. The fouling resulted in the tube inner diameter being reduced and caused the heat removal capability of the coolers to be reduced under Design Basis Accident conditions. The licensee also found that the four fan motor coolers were also fouled in a similar manner. Immediate corrective actions included cleaning out the heat exchangers, inspection of the tubes, and hydrostatic testing of the tubes. An assessment of the event and a root-cause evaluation determined that due to lack of a performance monitoring program and lack of flow (during the long steam generator outage in 1984) the tubes became fouled. To prevent recurrence, the licensee implemented plant modification M-968 which installed RTDs and differential pressure instruments as performance monitoring instrumentation on HVH-4. The instrumentation allows HVH-4 performance to be monitored, thereby providing detection capability for potential degradation of equipment due to biofouling. A side-stream monitor was also installed to allow for close monitoring and observation of biological growth inside piping and coolers. Additionally, a chlorination process was installed to treat the entire service water system to help prevent biofouling. Instrumentation similar to that installed on HVH-4 were installed on HVH-1, 2, and 3, during RO 13. Inspections of two HVH units, performed during RO 13, revealed no evidence of biofouling. Based on over two years of successful operation the licensee's long-term corrective actions have proven effective in preventing biofouling of the HVH units and associated motor coolers. This item is closed.

(Closed) LER 88-26, Inadvertent Safeguards Actuation. On November 14, 1988, the plant was in cold shutdown for refueling when a safeguards actuation was received from an inadvertent SI signal. The licensee's investigation revealed that the pressurizer SI block permissive was removed when licensee staff de-energized two of three reactor protection channels as part of a plant modification. This safeguard actuation did not result in an actual injection into the reactor coolant system; the breakers to the safety injection pumps were open and the discharge valves were closed and de-energized. Remaining safeguards equipment functioned as designed. The licensee's root cause investigation indicated that there were inadequate procedural precautions to ensure that safeguards be de-energized prior to removing two of three reactor protection channels. In addition, the licensee indicated that there was some miscommunication between the operations coordinator and the clearance center operators, in that, only a partial breaker lineup was required, yet a full breaker lineup was initiated resulting in the inadvertent Safeguards actuation. The intended partial breaker lineup would have prevented the inadvertent SI signal. Corrective actions included discussions between licensee staff, revisions to applicable procedures, and the placement of operator aids in the control room and on the DC breakers which supply the Safeguards System. The inspector held discussions with operations personnel, reviewed OST-163 revision 15, Safety Injection Test, and Emergency Diesel Generator Auto-Start on Loss of Power and Safety Injection and Emergency Diesel Trips Defeat (Refueling), and viewed the operator aids. At the time of the inspection, there were no inadvertent SI actuations since the one reported in the subject LER. The corrective actions taken by the licensee were deemed adequate by the inspector. This item is closed.

(Closed) LER 89-01, Hydrogen Introduced Into The Instrument Air System. This event is addressed in this section under the closure of URI 88-38-02.

(Closed) LER 89-02, Failure OF Fast Response RTD Thermowells. This item was not required to be reported per 10 CFR 50.73. However, a voluntary LER was filed because the event could be of interest to the industry and the NRC. Followup inspection is being tracked as IFI 89-07-02. Hence, because the LER is redundant to IFI 89-07-02, the LER is considered closed.

(Closed) LER 89-03, Licensee-Identified Violation Of 10 CFR 20.101 Due To Incomplete Contract Employee Forms NRC-4. The subject item was inspected and closed in IR 89-28 as IFI 89-FRP-01.

(Closed) LER 89-06, Reactor Trip Due To Loss Of Turbine E-H Control Power Supplies. Prior to restart from the reactor trip the inspectors verified that equipment repairs and protective circuitry setting adjustments were completed as described in the LER. During RO 13, Modification M-1046, Replacement of E-H Power Supplies, was installed to replace the original equipment. Originally, electronics for the EHC system were powered from two power supplies. Each power supply provided -15 VDC, +15 VDC, and +48 VDC. The modification replaced each unit with three individual power supplies, one for each voltage requirement. This new configuration eliminated the cascading failure mode which initiated the reactor trip. With installation of M-1046, the corrective actions described in the LER has been completed. This item is closed.

(Closed) LER 89-08, Potential Loss Of Residual Heat Removal Capability Due To Pump Flooding. Inspection Report 89-09, dated June 26, 1989, issued an NOV involving this matter. Followup of LER 89-08 will be incorporated into the inspection of the VIO, 89-09-05, hence LER 89-08 is considered closed.

(Closed) LER 90-11, Technical Specification Violation Due To Inoperable Fire Barrier Penetration (Fire Damper). The licensee was unable to determine when or how the fire damper was mispositioned. The inspectors verified that the corrective action specified in the LER had been completed. This action was to place a permanent label on the damper access door to inform personnel that the damper is to remain closed. The label reads "STOP Damper 77 is a closed damper - Do not open 77". This should preclude future inadvertent opening. This item is closed.

(Closed) IFI 88-03-03, Subcooling Margin. The subject item concerned failure to establish a basis for deviating from the recommended values in the WOG ERG when end path procedures were developed. Subsequently, a EOP inspection identified this as a general concern involving not only this specific item, but numerous other examples. This general concern was identified as IFI 89-16-01. Followup of IFI 88-03-03 disclosed that a calculated basis for the deviation was still scheduled to be performed. A statement was contained in the generic analysis applicability document, dated October 29, 1990, which indicated the values used were bound by the generic documents. However, not having the calculation performed to support the values used in the procedures and not having this documented in the setpoint document by September 28, 1990, was a failure to meet a commitment identified in the Response To NRC Inspection Report No. 50-261/89-16 dated December 8, 1989. The licensee has agreed to submit a revised response providing a date when this calculation and others which may not yet be completed, will be completed and incorporated into the setpoint document part of the PSTG. Followup will be performed under IFI 89-16-01, hence the subject item is closed.

(Closed) IFI 88-06-01, Review Inadvertent Shipment Of Contaminated Liquid To Quadrex. On February 24, 1988, the licensee made a shipment of two Sea/Land containers to the Quadrex Recycle Center in Oak Ridge, Tennessee. Although the shipping papers identified the physical form of the enclosed material as being a solid, approximately nine gallons of liquid had unknowingly been shipped. This issue was subsequently reviewed by a regional radiation specialist and violation 88-28-10 was identified for failure to indicate proper physical form of material on shipping papers. As this was a violation of minor safety/environmental concern for which adequate corrective actions had been taken, it was both cited and closed in IR 88-28. Consequently, IFI 88-06-01 is also considered closed.

(Closed) IFI 88-28-05, Licensee To Develop Methodology To Detect Biological Growth in HVH 1-4. The licensee has installed a computer-based fouling monitoring system which monitors the heat transfer resistance and fluid frictional resistance in a section of tubing which is representative (size and alloy composition) of the tubing in the HVH units. If fouling should occur, both heat transfer resistance and fluid frictional resistance should rise. The inspector conducted interviews with the HVAC and SW system engineers who indicated that the fouling monitor system, while not calibrated against traceable standards, does provide an indication of biofouling. This was validated during RO 13 when the section of tubing was cleaned and reinstalled. Original data was then compared to data obtained after the test section was cleaned. This data indicated that there was a slight positive change following cleaning, which indicated that some fouling had taken place in the two years the test section was interposed in the SW sidestream. However, visual examination of the test section revealed fouling was not evident. In addition to sidestream monitor, the licensee has implemented SW chlorination, and monthly performs EST-102, Performance Testing of HVH-4 Reactor Containment Fan Cooling Unit. The licensee considers this test to be representative of the other three HVH units. Instrumentation installed during RO 13 on the HVH-1, 2, and 3 will enable the licensee to perform performance testing on these HVH units. The licensee is revising EST-102 to incorporate this change. At the time of the inspection, no unsatisfactory results have been obtained. In addition, inspection performed of two HVH units revealed no fouled tubes. This item is closed.

(Closed) IFI 88-38-03, Review Selection Methodology, Adjustment, And Testing Of M-939 Breaker Setpoints. The subject modification (M-939) involved the replacement of MCPs in safety-related MCCs 5,6,9, and 10 in order to correct coordination problems. As discussed in IR 88-38, the MCPs being installed under M-939 were experiencing trip setpoint anomalies, requiring substantial adjustment from their calculated setpoints. Investigation into the matter determined that unrecognized limitations in the Westinghouse MCP setpoint application guide and personnel errors during preparation/review of M-939, resulted in an inadequate margin between locked rotor current and the MCP setpoint. Accordingly, more than 20 MCPs required upgrading to a larger size and approximately 120 required new setpoints. The inspector reviewed the completed modification package, including the design change notices (DCNs 939-19, 21, 22, and 24) which accomplished said rework, and verified the MCPs were subsequently tested prior to plant heatup above 200 degrees F. Actions taken with respect to identified casual factors (addressed in both SCR 89-07 and NCR 89-05) were also reviewed and found to be appropriate. This item is closed.

(Open) IFI 89-16-01, Develop A New PSTG. During inspection of IFI 88-03-03, the inspectors observed that IFI 89-16-01 had been considered as satisfactorily completed by the licensee and was listed as closed in the regulatory action item tracking system. The inspectors were concerned about the circumstances surrounding closure of IFI 89-16-01 when prior to this closure, outstanding work had been identified which was to be incorporated into the setpoint portion of the PSTG. This item remains open as described in closeout of IFI 88-03-03.

(Closed) IFI 88-28-01, Establish of EQ Lifetimes Inside CV Based Upon Actual Temperature Conditions. Temperatures used to calculate EQ lifetime of equipment in the CV were based on bulk average temperature in the CV. There were concerns that this bulk average temperature was not representative of actual temperatures in the immediate vicinity of EQ equipment. Procedure SP-797, Special Procedure for Monitoring CV Temperature, was performed to define the CV temperature profile. The actual temperatures inside the pressurizer cubicle were much higher than the bulk average temperature in the CV. As a result, the qualification lifetimes of EQ limit switches and solenoid valves were exceeded. The licensee has implemented a satisfactory PM schedule to change these components. This item is closed.

(Closed) URI 88-28-06, Review LER 88-21 And CV Operability Requirements After Opening Of CV Purge Exhaust Valves. This item concerned the events associated with the September 22, 1988 reactor shutdown which was prompted by leaking CV purge exhaust valves V12-8 and V12-9. The cause of the leakage, subsequent inspection/repair activities, and related corrective actions were adequately addressed in LER 88-21, which was closed in IR 90-12. With regard to operability requirements, the TS requires valves V12-8 and V12-9 to be closed whenever containment integrity is required except when purging for safety-related reasons. Accordingly, by design the valves will automatically open/shut upon initiation/securing containment purge fans. To verify system alignment control, the inspector reviewed OP-923, Containment Integrity, and OP-912, Penetration Pressurization System. From this review, it was confirmed that whenever containment integrity is required, OP-923 requires valves V12-8 and V12-9 to be operable (i.e., capable of automatic closure) and OP-912 requires the valves' associated PPS header to be in service. Furthermore, OP-912 specifies that PPS header pressure must be maintained above 42 psig or hot shut down must be achieved within 8 hours, followed by cold shutdown within the next 30 hours. To assure proper air pressurization occurs between the valves once a CV purge is secured, section 8.1 of OP-921, Containment Air Handling, requires PPS header pressure to be specifically verified. Consequently, the inspector had no further concerns. This item is closed.

(Closed) URI 88-28-08, Followup On Actions To Address Equipment Affected By An Increased CV Submergence Level. This item was also the subject of LER 88-022 and supplement 1 to LER 88-022. The LER was inspected and closed in IR 89-26. During this review, the inspector questioned the qualification of repairs made to penetration F-011 cables. These items are being tracked as URI 89-26-02 and 89-26-03. Thus, URI 88-28-08 is redundant to these items, and is considered closed.

(Closed) URI 88-38-02, Review Hydrogen Event Report, Associated Root Cause And Corrective Actions. This item concerned the intrusion of flammable concentrations of hydrogen into station and instrument air systems due to personnel error while conducting a main generator air tightness test on January 6 - 7, 1989. Specifically, personnel performing the test inadvertently cross connected plant air systems to the hydrogen supply for the main generator's cooling system. Considering the potential impact this test had on safety-related systems and the fact that it was being accomplished without a written procedure, a violation was issued accordingly on April 6, 1989 (EA 89-02). The licensee's corrective actions (addressed in the May 8, 1989 response to the violation and LER 89-01) included: (1) revising OP-507, Generator Hydrogen System, to provide written instructions for conducting a main generator air tightness test and to ensure proper clearance on the bulk hydrogen supply; and (2) revising OMM-005, Clearance and Test Request, to specifically set the bounds on what actions can be taken within a clearance boundary, as well as delineating how the introduction of fluids (gas or liquid) and system restoration is to be accomplished by Operations. Based on a review of the implemented procedure revisions, as well as, the Main Generator Air Test Procedure (Section 8.6 of OP-507) which was successfully completed in December 1990, corrective actions are considered appropriate to preclude recurrence of this event. This item is closed.

(Closed) VIO 89-03-02, Restoration Lineup Of OST-163 Results In BIT Inlet Valve Being In A Position Other Than That Established For OST-162. The inspectors reviewed the licensee's response dated May 5, 1989, to the NOV. The inspector verified that OST-162 and OST-163 was revised prior to their performance during RO 13 as committed. The revision involved combining OST 162 and OST-163 into one procedure designated as OST-163. This corrective action is considered adequate to preclude repetition. This item is closed.

No violations or deviations were identified.

8. Exit Interview (30703)

The inspection scope and findings were summarized on February 25, 1991, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings listed below and in the summary. Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

Item Number	Description/Reference Paragraph
91-01-01	NCV - Failure To Follow The Provisions Of A RWP As Required By PLP-016 (paragraph 2)
91-01-02	VIO - Activities Affecting Quality Were Not Performed In Accordance With Procedures And Drawings In That Modification Testing Was Not Performed AS Specified And An Incorrect Sized Fuse Was Installed (pragraphs 3 and 5)
91-01-03	VIO - Modification M-1016 Acceptance Tests Were Inadequate (paragraph 3)
91-01-04	VIO - OST-351 Revision 10 Was Inadequte In That It Did Not Completely Test The MSIV Logic (paragraph 4)
91-01-05	IFI - Review Fuse Control Program Development And Implementation (paragraph 5)

9. List of Acronyms and Initialisms

AC	Alternating Current
ACR	Adverse Condition Report
ALARA	As Low As Reasonably Achievable
ANF	Advanced Nuclear Fuels
ANSI	American National Standards Institute
APDMS	Axial Power Distribution Monitoring System
ASME	American Society of Mechanical Engineers
AVG	Average
BIT	Boron Injection Tank
C	Centigrade
CC	Component Cooling

CCW	Component Cooling Water
CFR	Code of Federal Regulations
CP&L	Carolina Power & Light
cpm	Counts Per Minute
CV	Containment Vessel
CWD	Control Wire Diagram
DC	Direct Current
DCN	Design Change Notice
EA	Enforcement Action
E & RC	Environmental and Radiation Control
e.g.	For Example
E-H	Electo-hydraulic
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
EE	Engineering Evalution
EHC	Electro-Hydraulic Control
EQDP	Environmental Qualification Documentation Package
ERFIS	Emergency Response Facility Information System
EST	Engineering Surveillance Test
F	Fahrenheit
HCV	Hand Control Valve
gpm	Gallons Per Minute
HE & EC	Harris Energy and Environmental Center
HP	Health Physics
HVH	Heating Ventilation Handling
Hx	Heat Exchanger
I&C	Instrumentation & Control
IFI	Inspector Followup Item
IR	Inspection Report
JCO	Justification For Continued Operation
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss Of Coolant Accident
LP	Loop Calibration Procedure
M	Modification
MCC	Motor Control Center
MCP	Motor Circuit Protector
MIC	Microbiologically Induced Corrosion
MSIV	Main Steam Isolation Valve
NCR	Non-Conformance Report
NCV	Non-cited Violation
NFS	Nuclear Fuels Section
NI	Nuclear Instrumentation
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
OMM	Operations Management Manual
OP	Operations Procedure
PC	Protective Clothing

PIC	Process Instrument Calibration
PLP	Plant Program
PM	Preventive Maintenance
PNSC	Plant Nuclear Safety Committee
PPS	Penetration Pressurization System
Psig	Pounds Per Square Inch - Gage
PSTG	Plant Specific Technical Guideline
PZR	Pressurizer
QC	Quality Control
RCCA	Rod Control Cluster Assembly
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RO	Refueling Outage
RPI	Rod Position Indication
RTD	Resistence Temperature Detector
RTGB	Reactor Turbine Generator Board
RWP	Radiation Work Permit
SCR	Significant Condition Report
SFP	Spent Fuel Pool
SI	Safety Injection
SP	Special Procedure
SPP	Special Process Pocedure
SRO	Senior Reactor Operator
SW	Service Water
SWBP	Service Water Booster Pumps
TAVG	Temperature Average
TS	Technical Specification
URI	Unresolved Item
UV	Undervoltage
V	Voltage
VAC	Volts Alternating Current
VDC	Volts Direct Current
VIO	Violation
WR/JO	Work Request/Job Order