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

Report No.: 50-261/89-09

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: April 18 - May 10, 1989

Inspectors: R E Carroll for 6/8/89
L. W. Garner, Senior Resident Inspector Date Signed

R E Carroll for 6/8/89
K. R. Jury, Resident Inspector Date Signed

Approved by: H C Dance 6/8/89
H. C. Dance, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

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

Results:

Two violations were identified: (1) failure to incorporate residual heat removal design basis leakage into specifications, drawings, and procedures following a change to the source term, paragraph 5.a; and (2) an inadequate technical review resulted in End Path Procedure EPP-10 not containing a precaution concerning potential safety injection pump runout with one pump injecting into two reactor coolant hot leg loops, paragraph 2.b.

A weakness in Fuel Handling Procedure FHP-003 was observed in that an acceptance criteria was not provided on a detachable data sheet, paragraph 2.a.

An operational weakness was observed in that an instrument channel associated with the reactor protection system was assumed to be operable without conducting an investigation into the reason for momentary bistable actuations, paragraph 2.c.

Determination that EDG fuel injectors require rebuilding during the next refueling outage is considered an example of a good predictive maintenance program, paragraph 3.

Retrieval activities associated with a fuel assembly dropped in the spent fuel pool was well planned, paragraph 5.b.

REPORT DETAILS

1. Licensee Employees Contacted

R. Barnett, Maintenance Supervisor, Electrical
R. Chambers, Engineering Supervisor, Performance
D. Crocker, Supervisor, Radiation Control
*D. Crook, Senior Specialist, Regulatory Compliance
*J. Curley, Director, Regulatory Compliance
C. Dietz, Manager, Robinson Nuclear Project
R. Femal, Shift Foreman, Operations
W. Flanagan, Manager, Design Engineering
*W. Gainey, Supervisor, Operations Support
*E. Harris, Director, Onsite Nuclear Safety
D. Knight, Shift Foreman, Operations
D. McCaskill, Shift Foreman, Operations
R. Moore, Shift Foreman, Operations
*R. Morgan, Plant General Manager
D. Myers, Shift Foreman, Operations
M. Page, Acting Manager, Technical Support
*D. Quick, Manager, Maintenance
D. Seagle, Shift Foreman, Operations
J. Sheppard, Manager, Operations
*R. Smith, Manager, Environmental & Radiation Control
R. Steele, Acting Supervisor, Operations
*H. Young, Director, Quality Assurance/Quality Control

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

*Attended exit interview on May 17, 1989.

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

2. Operational Safety Verification (71707)

The inspectors observed licensee activities to confirm that the facility was being operated safely and in conformance with regulatory requirements, and that the licensee management control system was effectively discharging its responsibilities for continued safe operation. These activities were confirmed by direct observations, tours of the facility, interviews and discussions with licensee management and personnel, independent verifications of safety system status and limiting conditions for operation, and reviews of facility records.

Periodically, the inspectors reviewed shift logs, operations records, data sheets, instrument traces, and records of equipment malfunctions to verify operability of safety-related equipment and compliance with TS. Specific

items reviewed include control room logs, operating orders, jumper logs, and equipment tagout records. Through periodic observations of work in progress and discussions with operations' staff members, the inspectors verified that the staff was knowledgeable of plant conditions; responding properly to alarm conditions; adhering to procedures and applicable administrative controls; and was aware of equipment out of service, surveillance testing, and maintenance activities in progress. The inspectors routinely observed shift changes to verify that continuity of system status was maintained and that proper control room staffing existed. The inspectors also observed that access to the control room was controlled and operations' personnel were carrying out their assigned duties in an attentive and professional manner. The control room was observed to be free of unnecessary distractions. The inspectors performed channel checks and reviewed component status and safety-related parameters to verify conformance with TS.

During this reporting interval, the inspectors verified compliance with selected LCOs. This verification was accomplished by direct observation of monitoring instrumentation, valve positions, switch positions, and review of completed logs and records.

Plant tours were routinely conducted to verify the operability of standby equipment, assess the general condition of plant equipment, and to verify that radiological controls, fire protection controls and equipment tag out procedures were being properly implemented. These tours verified the following: the absence of unusual fluid leaks; the lack of visual degradation of pipe, conduit, and seismic supports; the proper positions and indications of valves and circuit breakers; the lack of conditions which could invalidate EQ; the operability and calibration of safety-related instrumentation; and the operability of fire suppression and fire fighting equipment and emergency lighting equipment. The inspectors also verified that housekeeping was adequate and areas were free of unnecessary fire hazards and combustible materials.

In the course of the monthly activities, the inspectors included a review of the licensee's physical security and radiological control programs. The inspectors verified by general observation and perimeter walkdowns that measures taken to assure the physical protection of the facility met current requirements. The inspectors verified station personnel adhered to radiological controls.

a. Procedure Data Sheet Does Not Provide Acceptance Criteria

During movement of spent fuel into the DSC on April 25, 1989, a procedure weakness was noted by the inspectors. Step 8.2.3 of FHP-003, revision 5, Fuel Assembly Movement in the Spent Fuel Pit, requires hourly monitoring and recording of relative humidity on attachment 9.2. Neither step 8.2.3, nor attachment 9.2, provides an acceptance criteria and actions to be taken if the humidity

acceptance criteria is exceeded. This information is provided in section 6.0, Precautions and Limitations. Paragraph 6.16 of this section states that relative humidity shall not exceed 70% during movement of new or spent fuel. The 70% limitation is contained in the basis of TS, and hourly monitoring is required per TS 4.12.3.

The inspectors observed that attachment 9.2 had been detached from FHP-003 and that section 6.0 was not located in the spent fuel pool area. Subsequent to fuel movement, the inspectors inquired of an operator, the reasoning and basis for recording the humidity measurements. The operator completing the procedure was aware of the 70% limitation. Not providing an acceptance criteria on a data sheet which may be removed from the document containing the acceptance criteria constitutes a weakness in the procedure system.

b. Emergency Procedure Did Not Address SI Pump Runout

On April 4, 1989, the inspectors observed that EPP-10, Transfer to Hot Leg Recirculation, revision 2, step 3 required both hot leg injection valves, SI-866A and B, be opened. Opening SI-866A and B allows flow into the C and B RC hot leg loops, respectively. Step 4.6 required two SI pumps be started as available. OST-154, revision 11, Safety Injection System High Head Check Valve Test, contains the following precautions and limitations:

(1) Do not allow one SI pump to runout beyond 600 gpm or below 500 psig discharge pressure.

(2) At any time that only one SI pump is operating, one of the two injection headers (cold leg or hot leg) must be isolated to avoid possible pump runout.

(3) When running flow tests on the SI pumps (discharging to the system during refueling operations) use only one hot leg path when operating a single pump. Two hot leg paths may be used if two or more SI pumps are operating.

It appears that these statements are based upon a Westinghouse report entitled Safety Injection System Test Evaluation, issued June 1974. The report indicates that testing of one SI pump with both hot leg valves open was "omitted since pump runout flow exceeded allowable limit". EPP-10 authorizes operation with only one SI pump without precautions for potential runout. One reason for EPP-10 revision in September 1988, was to address that use of one SI pump is an allowed configuration in some cases. An inadequate technical review of this revision was the major contributor in failing to incorporate this precaution into the procedure. Failure to address potential runout with only one SI pump operating is a violation: EPP-10 Inadequately Addresses Potential Pump Runout With Only One SI Pump Injecting Into Two Hot Legs, 89-09-01.

The inspectors reviewed the applicability of the one SI pump precaution to injection into three cold legs. This configuration would be the expected alignment during a design basis LOCA. In 1988, Westinghouse performed a calculation which demonstrated that this operating mode would be acceptable; however, the 1974 flow test did not conduct testing which demonstrated this flow configuration was acceptable. The inspectors' review of the 1974 flow test results for other pump combinations into the cold legs, indicates one SI pump injection into three cold legs may result in operation approaching runout conditions.

In the exit interview, the licensee indicated that they believe that runout would not occur for neither the three cold leg injection pathway nor for the dual hot leg pathway. However, they did agree that existing available information supports that a limitation should be placed on one SI pump injection into the dual hot leg pathway. Additional review is required to determine what testing, if any, should be performed to support operation of the system in the current configuration. This is an URI: Determine If One SI Pump Injection Into Three Cold Legs Should Be Demonstrated, 89-09-02.

c. Instrument Evaluations To Determine Operability Needs Enhancement

An operational weakness was observed, in that, an instrument channel associated with the reactor protection system was assumed to be operable without conducting an investigation into the reason for momentary bistable actuations. The cause was assumed to be known because of a recent similar problem with a redundant instrument loop. Investigation later determined that the instrument was operable. The details of this issue are discussed below:

On May 3, 1989, the inspectors were informed that RC loop C low flow instrument FT-436 appeared to be operating erratically. The instrument was spiking low 12 to 15 times per shift, thereby causing momentary low flow bistable actuations. This condition had begun approximately three days earlier, after the redundant transmitter FT-435 had experienced a similar problem. The FT-435 problem had been corrected by venting the transmitter. The inspectors were informed that part of the air bubble which had been in FT-435 had apparently moved into the FT-436 portion of the common high pressure line. When corrective actions were addressed, the licensee indicated that they believed that the bubble would dissolve. When asked if the spiking frequency was decreasing, the licensee indicated that they believed that it was; however, the number of occurrences had not been recorded nor trended. Furthermore, the inspectors were informed that no troubleshooting had been performed because the spiking was in the conservative direction and was similar to the FT-435 problem. The inspectors pointed out that there were no alarms or other installed means by which it could be determined if spiking was occurring in the

non-conservative direction. In addition, spiking of this nature could be the result of an electrical problem with the instrument loop. Comparison of the RTGB indicator with the other two redundant instruments revealed that FT-436 was varying only slightly from the other two channels. The inspectors questioned if the instrument's response time would meet that assumed in transient analysis, and what the basis was for not declaring the instrument out of service (i.e., tripping the channel to maintain the degree of redundancy specified by TS 3.5.1.3 and TS Table 3.5-2). Since the observed spiking was in the conservative direction (the channel trips), OMM-001, Operations - Conduct of Operations, revisons 19, section 5.14.2.1 was considered to apply. This section in part addresses channels deviating by a known constant amount. If this constant deviation is in a conservative direction, an appropriate trip need not be inserted. The inspectors do not believe that this section applies to erratic or spiking instrumentation. Since the ability of the instrument to respond within the time assumed had not been addressed, the inspectors, after consultation with NRC Region II management, informed the licensee that the channel should be considered inoperable. The licensee promptly declared the channel inoperable and took the action required by TS. On May 4, plant management discussed the matter with the inspectors, contending that the spiking could only occur in the conservative direction and that the instrument tracked the other channels; therefore, they considered the instrument was operable. Furthermore, since troubleshooting was hampered by having the channel tripped, the licensee stated their intent to return FT-436 to service. Troubleshooting would then be performed to determine, if possible, the exact nature of the problem and occurrence trending would be performed. In addition, the licensee indicated that if the spiking occurrence frequency was not decreasing, the unit would be reduced below P-8, the one RCP trip bypass permissive setpoint, and the instrument loop would be vented during the subsequent weekend. After consulting with Region II management, the inspectors informed the licensee that the NRC did not object to this course of action. Subsequently, FT-436 was returned to service. The instrument was not vented since it was spiking only three or four times during most days. Occasionally, FT-436 would spike as many as ten times per day. The licensee has also determined from instrument data that there was no information which indicated that the FT-436 response time to changes in flow was adversely affected. If the transmitter is still spiking by the end of May, the licensee plans to vent the instrument lines when power is decreased for turbine valve testing.

During the exit interview, the inspectors discussed with plant management the need to conduct a proper investigation when an instrument loop is not functioning correctly. In particular, a determination needs to be made as to whether an observed abnormal behavior indicates an instrument loop may or may not perform its

function as described in transient analysis. In the case discussed above, the licensee, having assumed the problem was due to air in the instrument loop, failed to evaluate if this would adversely effect the 0.2 second instrument loop response time. The licensee stated that they believed that the guideline of OMM-001 had applied to FT-436; however, the licensee did agree to review their current practices in this area. This review includes contacting other utilities to determine what actions are typically taken to address this type of situation. This is an IFI: Review Actions To Be Taken When An Instrument Loop Exhibits Random Erratic Behavior, 89-09-03.

One violation was identified within the areas inspected.

3. Monthly Surveillance Observation (61726)

The inspectors observed certain surveillance activities of safety- related 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 met; the tests were completed at the required frequency; the tests conformed to TS requirements; the required administrative approvals and tagouts were obtained prior to initiating the tests; the testing was accomplished by qualified personnel in accordance with an approved test procedure; and the required test instrumentation was properly calibrated. Upon completion of the testing, the inspectors observed that the recorded test data was accurate, complete, met TS requirements, and test discrepancies were properly rectified. The inspectors independently verified that the systems were properly returned to service. Specifically, the inspectors witnessed/reviewed portions of the following test activities:

OST-010 (revision 9)	Power Range Calorimetric During Power Operation
OST-401 (revision 22)	Emergency Diesels
RST-001 (revision 33)	Radiation Monitor Source Checks
EST-058 (revision 4)	SI-890A and 890B Check Valve Test

The inspectors discussed with the cognizant engineer the A EDG OST-401 test data taken on May 1, 1989. The engineer indicated that trends on some cylinder exhaust temperatures indicate deterioration in fuel injector performance. This does not effect operability of the EDG, and plans are in progress to have these injectors rebuilt during the next outage. The inspectors consider this as an example of good predictive maintenance.

No violations or deviations were identified within the areas inspected.

4. Monthly Maintenance Observation (62703)

The inspectors observed several maintenance activities of safety-related systems and components to ascertain that these activities were conducted in accordance with approved procedures, TS, and appropriate industry codes

and standards. The inspectors determined that these activities did not violate LCOs, and that redundant components were operable. The inspectors also determined that activities were accomplished by qualified personnel using approved procedures; QC hold points were established where required; required administrative approvals and tagouts were obtained prior to work initiation; proper radiological controls were adhered to; and the effected equipment was properly tested before being returned to service. In particular, the inspectors observed/reviewed the following maintenance activities:

MST-901 (revision 19)	Radiation Monitoring System
OWP-004 (revision 6)	Containment Spray
WR/JO 89-AEPM1	Repair SI-890B Bonnet to Body Leak

On May 2, 1989, while observing maintenance activities on SI-890B, the B CV spray pump discharge check valve, the inspectors observed that the only post-maintenance testing specified on WR/JO 89-AEPM1 was an examination for external leakage from the valve while at operating conditions. When the inspectors questioned if this was all the testing to be performed, they were informed that no testing of SI-890B other than that required by Section XI of the ASME code was required. ASME Section XI requires only a leak check after a gasket replacement and per a code exemption request response from the NRC, disassembly and visual examination of the full stroke of the check valve is sufficient to comply with Section XI requirements. These requirements were specified to be performed by the WR, and it was determined no further testing, such as a partial flow test, was required. Item 9.a of Regulatory Guide 1.33, revision 2, as required by TS 6.5.1.1.1.a, requires that maintenance which can affect the performance of safety-related equipment be performed in accordance with written procedures appropriate to the circumstances. 10 CFR 50, Appendix B, Criterion V, requires instructions to include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. The inspectors considered a partial flow test was necessary as a qualitative acceptance criteria after partial disassembly of the valve. This item was discussed with the Plant Manager. Prior to returning the B CV spray loop to service, the licensee performed additional testing.

The licensee agreed that additional testing requirements should have been included on the WR since the valve was almost completely disassembled. A PLP-026 investigation is to be conducted in order to determine the root cause for the failure, to include appropriate test requirements, and to determine what actions, if any, are required to prevent recurrence. However, during the exit interview, the licensee stated that a partial flow test would not be required for a limited work scope such as removal and replacement of a bonnet with an attached flapper assembly (assuming the flapper assembly is not disassembled or adjusted). The inspectors believe that this type of activity would require partial flow testing. This belief is based in part on Attachment 1, paragraph 2, of GL 89-04,

Guidance on Developing Acceptable Inservice Testing Programs, issued April 3, 1989. This paragraph requires a partial flow test be performed, if possible, after reassembly. Resolution of what constitutes disassembly and reassembly of a check valve is considered an URI: Resolve What Degree Of Maintenance Activity On Check Valves Warrants A Partial Flow Test After Reassembly Per GL 89-04, 89-09-04.

No violations or deviations were identified within the areas inspected.

5. Onsite Followup of Events at Operating Power Reactors (93702)

a. RHR Pit Leakage Design Basis Could Not Be Met During Accident Conditions

On April 6, 1989, the resident office was notified that a potential common mode failure of both RHR trains may exist due to flooding. The RHR pump bays are separated by a concrete shield wall approximately eight feet high at its lowest point. The RHR pump motor pedestal is approximately four feet high. As part of the RHR system design basis document review, the question was raised whether the wall was intended to serve a flood protection function. As constructed, the wall did not provide separation since the two pump bays were connected at floor level by a six-inch diameter open ended pipe. During resolution of this issue on April 10, 1989, the PNSC and NED determined that the system design basis to detect and isolate a 50 gpm leak into the RHR pit within 30 minutes did not appear to be obtainable during accident conditions. Later that evening, it was confirmed that during the recirculation mode of operation, a passive failure resulting in a leak could not be isolated, since high radiation levels would not allow personnel access to certain manual valves required for isolation. Anticipated radiation fields could be as large as several thousand Rem/hr. Potential passive failures considered included: flange leaks, pipe cracks, packing leaks, tube leaks, and pump seal leaks on either the SW, CCW or RHR components in the RHR pit. Anticipated radiation levels were based upon the source term associated with TMI Action Item II.B.2, Shielding Modifications for Vital Area Access. Manual valves which would be inaccessable after initiation of the recirculation phase include: RHR-752A and B, the RHR pump suction valves; SW-75, -76, -77, and -78, the RHR room coolers' (HVH-8A and B) supply and return valves; and CC-768A and B, the RHR pump seal coolers' supply valves. Inherent to the accident scenario is the assumption that the RHR pit sump pumps would be unavailable since they are not environmentally qualified and are not powered from emergency onsite power.

At the time of discovery, the unit was shutdown for removal of a loose part from C S/G (see Inspection Report 89-08). Prior to resuming power operations, procedure changes and temporary modifications were implemented to address the issue until a permanent solution is identified. Independence of the pump bays was established by

grouting the six inch diameter pipe. EPP-9, Transfer to Cold Leg Recirculation, was revised to: (1) secure SW to the RHR room coolers by closing SW-75, -76, -77 and -78; (2) isolate the RHR pump suction lines from one another by closing either RHR-752A or B; and (3) install a temporary RHR pit level measuring system. Temporary modification 89-709 supplied two level devices to be installed by operators. Each device, one for each bay, consists of a float, a cable and counterweight. The float is to be lowered into the RHR pump bay, the cable suspended over a pulley system and the counterweight hung adjacent to a level scale painted on a wall outside the RHR pit. The above mentioned items are to be completed immediately prior to initiating RHR recirculation. A revision to the EPP-Foldouts was made to require hourly monitoring of the temporary level system. A new procedure, EPP-24, Isolation of Leakage in the RHR Pump Pit, was issued on April 13, 1989. This procedure provides instructions on the use of the level system to determine which bay contains the leak and the steps required to isolate the leak while still maintaining one RHR pump operating. The licensee described this event in LER 89-008.

The acceptability of continued operation until the next refueling outage based on the above described actions is documented in JCO 89-05. The inspectors reviewed the JCO and associated engineering evaluations. Two specific items addressed in the JCO were the leakage from the CCW and SW systems. The RHR pump vendor indicated that the RHR pump seals could operate indefinitely at the temperatures anticipated during the recirculation phase of an accident. However, it was considered prudent to have the RHR pump seal coolers in service; therefore, it was decided to continue to supply CCW to the seal coolers during the recirculation phase of an accident. This was based in part on the determination that leakage from the CCW lines supplying the RHR pump seal coolers was a relatively small contributor to core melt frequency for the assumed event. The acceptability of removing the RHR room coolers from service by securing service water to HVH-8A and B is documented in EE 88-080. EE 88-080 was developed to support JCO 88-002, approved July 1, 1988. JCO 88-002 addressed operation of the RHR pumps under post LOCA conditions without HVH-8A and B in service. HVH-8A and B were assumed to fail since no EQ package had been developed to address the effect of radiation on the fan motors (see Inspection Report 88-16). JCO 88-002 and EE 88-080 had been previously reviewed by the inspectors. The acceptability of these evaluations to the current issue was confirmed.

The inspectors witnessed shift training on the revised EPP-9 and newly issued EPP-24. This training included a field walkdown to identify the location of manual valves which would require manipulation. Additionally, the inspectors witnessed simulation of the revised section of EPP-9. Problems encountered during the simulation were adequately addressed by the licensee. These actions were completed prior to unit restart on April 15, 1989.

The UFSAR does not address the design basis statement that an operator can detect and isolate a 50 gpm leak within 30 minutes. UFSAR Chapter 6, section 6.3.2.5.5, Recirculation Loop Leakage, does state that valving is provided to permit the operator to individually isolate each RHR pump. Manually operated valves RHR-752A and B are the valves required for isolation of RHR pumps A and B, respectively. As described in the preceding paragraphs, these valves are not accessible due to postulated radiation levels after initiation of recirculation. Hence, the existing RHR configuration does not reflect the design as described in the UFSAR; however, it appears that the RHR pit was considered accessible when the plant was licensed. Statements contained in analysis WCAP-12070 indicate that this area is accessible for maintenance on a RHR pump when the other pump is operating in the recirculation mode. This analysis was issued in December 1988 as a compilation of original design information. This compilation is based upon both documentation and personal recollections. The licensee believes that the source term used in the original plant shielding analysis would support the statements contained in WCAP-12070. As discussed previously, the radiation levels now anticipated are based upon analysis performed to comply with TMI item II.B.2. The licensee's review of these later calculations indicated that there is a large amount of conservatism in this analysis. Thus, they believe if this analysis were reperformed, the areas required for leakage isolation may be accessible.

Statements provided in WCAP-12070 are the only documented basis identified to date which indicate that a 50 gpm leak into the RHR pit must be isolable. The time criterion is based upon the calculated time available to isolate a 50 gpm leak prior to RHR motor damage. The volume in each pump bay (below the RHR motor pedestal) is 200 cubic feet; thus a 50 gpm leak must be isolated within 30 minutes. The assumption in the calculation was that the two RHR pump bays were separated. This was not the as-found configuration since the pump bay sumps were connected by a six-inch diameter pipe. The connection had probably existed since plant construction.

In a response to NUREG 0737 Item II.B.2, dated December 31, 1980, the licensee stated: "This response to NUREG 0737 Item II.B.2 together with the CP&L responses to NUREG 0578 dated December 31, 1979, and supplemented March 31, 1980, constitutes CP&L's complete response on this item. CP&L considers this item to be complete." Neither this response nor its referenced documents address the RHR leakage detection and isolation design criteria. Hence, during implementation of II.B.2 adequate design controls were not established to assure design basis were properly incorporated into design documents and plant procedures.

In summary, the licensee's design basis document review determined that available information indicates inaccessibility to areas required to isolate a 50 gpm leak into the RHR pit during the

recirculation phase of an accident. No credit is taken for the RHR pit sump pumps since they are not powered from emergency onsite power sources. Futhermore, even if power was available, the installed sump pumps and associated control circuits cannot be assured to remain functional since the EQ of these items have not been demonstrated. Under the above described conditions, a 50 gpm leak or less would eventually result in sufficient flooding to damage both RHR pump motors. The loss of both RHR trains during the recirculation phase would result in the loss of all ECCS capability. The licensee has initiated compensating action in hardware and administrative controls until a long term fix has been approved and implemented during the next refueling outage. The failure to assure that design basis are correctly translated into specifications, drawings, and procedures is a violation of 10 CFR 50 Appendix B Criterion III: Design Control Measures Were Not Adequately Established To Assure That The 50 Gpm Leak Isolation Capability Design Basis Was Correctly Translated Into Specifications, Drawings, and Procedures For The RHR System, 89-09-05.

b. Spent Fuel Assembly Disengaged From Grapple During DSC Loading

On April 26, 1989, at approximately 12:35 a.m., a spent fuel assembly became uncoupled from the fuel handling tool and fell against the spent fuel pool wall. Personnel working in the spent fuel pool area immediately evacuated the area. Air samples and radiation monitors showed no increase over normal background levels. At the time of occurrence, a spent fuel assembly was being loaded into a DSC in preparation for onsite storage in the ISFS facility. Five fuel assemblies had been successfully loaded into the DSC when the operator experienced difficulty in positioning the sixth. After several attempts, the assembly caught on the top DSC grid-work while being lowered. The grapple cable slackened, the assembly separated from the tool, and fell against the spent fuel pool wall. The inspectors estimated that the assembly formed a 40 degree angle with the wall and incurred a 25 degree torsional twist. The licensee prepared a special procedure and successfully retrieved the assembly on April 26. The assembly was positioned in the fuel elevator for inspection; no damage was observed. The assembly has been returned to the spent fuel pool storage location.

The inspectors reviewed the special procedure, attended the PNSC which approved the special procedure, and attended the pre-job briefing. The inspectors determined that the retrieval activity was well planned and contained sufficient safety precautions and contingency plans.

Visual inspection of the top nozzle blocks of the assemblies which were contained in the DSC at the time of the event revealed no assembly damage had occurred. As a result of the fuel assembly falling onto the DSC, the DSC was unloaded and removed from the spent

fuel pool for repair of minor damage to the grid-work. After repair, the DSC was returned to the spent fuel pool and successfully loaded with seven spent fuel assemblies on April 28 without any further difficulties. The assembly which fell against the wall will remain in the spent fuel pool until its final disposition is decided.

Investigation into the event revealed that the most probable cause was that the tool had been engaged on the leaf springs instead of in the top nozzle block. Measurements of the tool revealed no dimensional reason for the failure to properly engage the assembly. Thus, either an obstruction had caused the improper latching or an operator error had occurred. The actual root cause is still being evaluated; however, a potential contributor to this event was determined to be a loss in fuel handling efficiency. During the previous two refueling outages, fuel movements were performed by contract personnel. Immediate corrective action consisted of retraining the operating crews on fuel handling techniques and manipulations prior to performing additional fuel movements, including removal of the five assemblies from the damaged DSC. Also, potentially contributing to this event was bowing of the fuel assembly. This phenomena can hinder latching an assembly. Bowing is much more pronounced on older assemblies due to the pattern in which they were irradiated.

Long term corrective action is being developed as part of the PLP-026 incident review process. This is an IFI: Review Corrective Actions To Be Addressed In PLP-026 Associated With A Dropped Fuel Assembly, 89-09-06.

One violation was identified within the areas inspected.

6. Onsite Review Committee (40700)

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 the April 26, 1989 PNSC concerning the dropped fuel assembly. It was ascertained that provisions of the TS dealing with membership and review process were met. Previous meeting minutes were reviewed to confirm that decisions and recommendations were accurately reflected in the minutes.

No violations or deviations were identified within the areas inspected.

7. Exit Interview (30703)

The inspection scope and findings were summarized on May 17, 1989, with those persons indicated in paragraph 1. Excluding item 89-09-05, the inspectors described the areas inspected and discussed in detail the inspection findings listed below and in the report summary. The licensee

was informed of item 89-09-05 on June 1, 1989. Licensee's comments concerning particular items are discussed in the appropriate paragraph. Proprietary information is not contained in this report.

Item Number	Description/Reference Paragraph
89-09-01	VIO - EPP-10 Inadequately Addresses Potential Pump Runout With Only One SI Pump Injecting Into Two Hot Legs, paragraph 2.b.
89-09-02	URI - Determine If One SI Pump Injection Into Three Cold Legs Should Be Demonstrated, paragraph 2.b.
89-09-03	IFI - Review Actions To Be Taken When An Instrument Loop Exhibits Random Erratic Behavior, paragraph 2.c.
89-09-04	URI - Resolve What Degree Of Maintenance Activity On Check Valves Warrants a Partial Flow Test After Reassembly Per GL 89-04, paragraph 4.
89-09-05	VIO - Design Control Measures Were Not Adequately Established To Assure That The 50 GPM Leak Isolation Capability Design Basis Was Correctly Translated Into Specifications, Drawings, and Procedures For The RHR System, paragraph 5.a.
89-09-06	IFI - Review Corrective Actions To Be Addressed In PLP-026 Associated With The Dropped Fuel Assembly, paragraph 5.b.

8. Acronyms and Initialisms

ASME	American Society of Mechanical Engineers
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CP&L	Carolina Power & Light Company
CV	Containment Vessel
DSC	Dry Shielded Canister
ECCS	Emergency Core Cooling System
EE	Engineering Evacuation
EDG	Emergency Diesel Generator
EPP	End Path Procedures
EQ	Environmental Qualifications
EST	Engineering Surveillance Test
FI	Flow Indicator
FT	Flow Transmitter
FHP	Fuel Handling Procedure
GL	Generic Letter
gpm	Gallons Per Minute

HVH	Heating Ventilation Handling
IFI	Inspector Followup Item
JCO	Justification For Continued Operation
LCO	Limiting Condition for Operation
MST	Maintenance Surveillance Test
NED	Nuclear Engineering Department
NRC	Nuclear Regulatory Commission
OMM	Operations Management Manual
OST	Operations Surveillance Test
OWP	Operations Work Procedure
PLP	Plant Procedure
PNSC	Plant Nuclear Safety Committee
QC	Quality Control
RC	Reactor Coolant
RCP	Reactor Coolant Pump
Rem/hr	Roentgen Equivalent Man/Hour
RHR	Residual Heat Removal
RST	E&RC Surveillance Test
S/G	Steam Generator
SI	Safety Injection
SW	Service Water
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
*URI	Unresolved Item
WCAP	Westinghouse Corporation Atomic Power
WR	Work Request
WR/JO	Work Request/Job Order

* Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations or deviations.