U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Report Nos: 50-335/97-04, 50-389/97-04

Licensee: Florida Power & Light Co.

Facility: St. Lucie Nuclear Plant, Units 1 & 2

Location: 6351 South Ocean Drive
Jensen Beach, FL 34957

Dates: March 30 - May 10, 1997

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EXECUTIVE SUMMARY

St. Lucie Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-335/97-04, 50-389/97-04

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes inspections conducted by regional personnel.

Operations

- The licensee performed appropriate actions and controls to enter a reduced inventory condition on Unit 2. Crew sensitivity to the evolution was proper (paragraph O1.2).

- The Equipment Clearance Order process was reviewed and found adequate to safely isolate equipment for personnel safety and that operators where knowledgeable of the process and requirements of the procedure. The licensee was proactive in identifying declining trends in clearance procedure adherence. Interim corrective actions have not been effective in correcting the problems; however, the final corrective actions are still being developed. A violation was identified for several examples of problems following the governing procedure (paragraph O1.3).

- Walkdowns of accessible portions of the Unit 2 Intake Cooling Water system and the Unit 2 Component Cooling Water System found equipment operability, material condition, and housekeeping acceptable (paragraph O2.1).

- The licensee exhibited conservative decision making to determine the source of leakage inside the Unit 1 containment. A subsequent shutdown was well controlled and the inspector noted good cooperation between Reactor Engineering and Operations in controlling power while in Mode 2 (paragraph O2.2).

- An Event Response Team review of an incident involving a lifting of a shutdown cooling relief valve on Unit 2 was effective in determining the probable cause of the occurrence. The licensee's corrective actions were appropriate (paragraph O2.3).

- Operators took the appropriate actions in response to two dropped rod events on Unit 2. The correct Technical Specification actions were taken. The licensee has planned modifications to be implemented during the next refueling outage which will improve the reliability of the system (paragraph O2.4).

- Unit 2 fuel handling was completed in accordance with approved procedures. Personnel operating equipment appeared to be very knowledgeable on its use and operated it in a careful and deliberate manner (paragraph O2.5).

- The licensee's use of Reactor Controls Operator overtime for routine operations was heavy and the need for the overtime was not unforeseen. Consequently, the licensee was found to be in violation of TS 6.2.2.f. The licensee's shortage of operators (the cause for the overtime) was the result of poor planning in the past, combined with promotions of individuals out of the Operations organization. The overtime was considered to have been preventable, had management focused on the issue (paragraph O8.5).

Maintenance

- The licensee's performance of setpoint surveillance testing on the Main Steam Safety Valves was satisfactory (paragraph M1.1).

- The lift of the UGS was performed under the proper maintenance controls. The licensee's recovery actions to complete the lift safely after discovering hot particles and high radiation levels was good. Coordination between Operations, Maintenance, and Health Physics was judged to be excellent (paragraph M1.2).

- The replacement of Emergency Diesel Generator relays and sockets was a well-coordinated complex activity. The maintenance personnel performing the work were extremely knowledgeable about the activity. Although the work area was located inside a small cabinet containing other electrical components, the workers were careful and deliberate in their actions not to affect other components (paragraph M1.3).

- Fuel Handling Building Ventilation System testing was performed in a controlled manner. The participants had a complete understanding of the expected system response during performance of the surveillance. Good communication was observed by the inspector (paragraph M1.4).

- The pressure boundary ISI activities were well organized and work activities observed were conducted in accordance with approved procedures. Containment surveillance procedures had documented acknowledgement of recent changes to NRC regulations. (Paragraph M1.5)

- Failure analysis of a Unit 1 Safety Injection System socket weld connection was very well done. (Paragraph M1.5)

- Replacement of pump casings on the site fire protection pumps appears to have been a successful operation. (Paragraph M1.5)

- The licensee's program for inspection of SGs appears to be well managed and conducted in a conservative manner. The procedures reviewed were found to be adequate for the intended operations. In-situ pressure testing and plugging operations were conducted in a professional manner. (Paragraph M1.6)

- At the beginning of the Unit 2 refueling outage the inspectors and the licensee identified several instances of less than adequate FME control.

The licensee instituted corrective actions and by the end of the report period the inspectors noticed much improvement (paragraph M2.1).

Engineering

- Engineering accurately reflected the output of the full core off-loading calculation into its cycle nine refueling outage safety analysis. The licensee also transferred all vital information from the safety analysis into operating procedures, although the procedures, as written, were more restrictive than necessary (paragraph E2.1).

- The performance of Unit 2 Safeguards Testing was challenging to the Operations and Engineering staff. Several equipment failures were identified during the test. The completed root cause analyses were thorough and appropriate for each problem. The reperformance of the test had not occurred at the end of the inspection period (paragraph E2.2).

- Haul route testing for the replacement Unit 1 steam generators was completed satisfactorily. The replacement steam generators were received on site and moved into the protected area without incident (paragraphs E8.1 and E8.2).

Plant Support

- Backshift walkdowns indicated that protected area barriers were in good condition, the isolation zones well lit, and the appropriate compensatory guard postings in place (paragraph S2.1).

Report Details

Summary of Plant Status

Unit 1

Unit 1 entered the report period at full power. On April 18, the unit was brought off-line to allow personnel to enter the containment to determine the source of Safety Injection Tank leakage. An Unusual Event was declared early the next morning due to primary pressure boundary leakage. The plant entered cold shutdown on April 20. The licensee restarted the plant on April 23 and it achieved full power the next day. Unit 1 remained at full power for the remainder of the period.

Unit 2

Unit 2 entered the report period at full power. It remained there until April 12 when power was reduced to approximately 80 percent for Main Steam Safety Valve Testing. The unit was shutdown on April 14 to begin the refueling outage. The outage continued for the remainder of the report period.

I. Operations

01 Conduct of Operations

01.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

01.2 Reduced Inventory Operations (71707)

a. Inspection Scope

On April 18, 1996, at 11:20 pm, the licensee entered reduced inventory to install the Steam Generator Nozzle Dams. While the Reactor Coolant System (RCS) was at reduced inventory, a number of controls and procedures were implemented to ensure the safety of the unit. The inspector reviewed the preparations for draining the RCS and observed portions of the evolution.

b. Observations and Findings

Two procedures, NOP 2-0410022, Revision 24, "Shutdown Cooling" Appendix A "Instructions for Operation at Reduced Inventory or Mid-loop Conditions" and OP 2-0120021, Revision 30, "Draining the Reactor Coolant System" executed the majority of the controls. The following items were verified prior to this evolution:

- Containment Closure Capability - Instructions were issued to accomplish containment closure. The equipment hatch was open but

the licensee closed this penetration prior to beginning the reduction in RCS inventory. The inspector reviewed the penetrations which were to remain open at the time of the drain down and verified that closure capability was available.

- RCS Temperature Indication - Two Core exit Thermocouples (CETs) were available on each Safety Parameter Display System (SPDS) channel.

- RCS Level Indication - Independent RCS wide and narrow range level instruments, which indicated in the control room, were operable. Additionally, a Tygon tube loop level in the containment was installed and was visible to a dedicated operator in contact with the control room. A television camera/monitor system was later installed to allow remote monitoring in the control room.

- RCS Level Perturbations - When RCS level reduction was initiated, additional operational controls were invoked. Operations did not allow any maintenance that might affect RCS level or shut down cooling.

- RCS Inventory Volume Addition Capability - The 2B High Pressure Safety Injection (HPSI) pump and the 2A charging pump were available for inventory addition, as were two trains of shutdown cooling.

- Vital Electrical Bus Availability - Operations did not plan to release busses or alternate power sources for work while the unit was in a reduced inventory.

- Pressurizer Vent Path - The manway atop the pressurizer was removed to provide a vent path. Operations verified that the manway was unobstructed every four hours.

The drain down was performed in a very controlled manner. The inspector noted that the crew's supervision maintained a cognizance of RCS level and draining rate. Generally, the crew maintained their attention to the task. The Control Room door was posted with a sign informing all personnel that a sensitive evolution was in progress and only necessary personnel should enter. Despite this, several unnecessary workers entered the Control Room only to be asked to leave by the operating crew.

c. Conclusions

The licensee performed appropriate actions and controls to enter a reduced inventory condition. Crew sensitivity to the evolution was proper.

01.3 Equipment Clearance Order Issues (71707)

a. Inspection Scope

During a two-week time frame during the inspection period, several problems were identified with clearances that were either hanging or being hung. The inspector conducted a review to determine the extent of the problems and to determine if appropriate root cause analysis and corrective actions were being implemented.

b. Observations and Findings

On April 19, an Equipment Clearance Order (ECO), isolating the 2B2 circulating water pump, had a boundary modification performed to allow Electrical Maintenance to bump the pump's motor to verify proper rotation. At the time, Mechanical Maintenance was also working under the same ECO. Procedure OP 0010122, Revision 68, "In-Plant Clearance Orders" did allow a boundary modification to occur to perform this type of check. However, in Section 8.15.9, the procedure required that all Clearance Holders approve the modification to the clearance prior to execution. In this case, the Maintenance Supervisor released the clearance to allow the modification and failed to inform the Mechanical Foreman, a clearance holder. On April 25, the Foreman walked down the clearance prior to recoupling the pump. He noted that the breaker to the pump was no longer tagged out and that he had men working in the vicinity of the pump. The licensee immediately had an operator tag open the breaker.

The licensee's investigation determined that the modification was inadequate. Section 8.15.6 of the subject procedure stated that ". . . A boundary modification NOT requiring a work stoppage shall only be performed in a manner that does NOT create any unsafe conditions for the personnel working within the boundaries . . . " This implied that this may require additional tags to allow other work to continue. Not only was the foreman not informed of the modification, but there were no tags added, such as to the disassembled coupling, to prevent the rotation of the pump while work continued. The licensee determined the cause to be due to human performance and held stand down meetings with operating and maintenance personnel to reiterate the importance of compliance with the clearance procedure. The licensee also verified that all existing boundary modifications were adequate.

On April 25, the licensee was in the process of restoring the 2A Emergency Diesel Generator (EDG) systems. A boundary modification was required to allow retesting of newly installed relays. The Clearance Holder requested the assistance of the System and Component Engineer in determining appropriate boundaries. This recommendation was based only on observed work. The clearance was not referenced for open work orders, and an open work item on the lube oil system was missed. Subsequently, when the boundary modification was executed, the DC lube oil soakback pump started. This was immediately secured by the engineer by pulling a fuse. Only after this point did the licensee realize that

the lube oil system had an open work order. Section 8.15.11 of OP 2-0010122 required that the review and approval cycle for hanging the new tags "shall be performed in the same manner as the original Clearance Order," and Section 8.15.6 required that any boundary modification not create a hazard to other work authorized within the ECO. The licensee held standdown meetings with those involved.

On April 28, the licensee began to execute an electrical clearance order (ECO 2-97-03-423R) to allow Thermolag removal in the Reactor Auxiliary Building (RAB). The ECO requestor provided a list of instrumentation that would be lost while the clearance was in effect. Upon opening the first breaker, a Containment Evacuation alarm was received. The operating crew verified that this was an unexpected response and reshut the breaker. A licensee investigation determined that the loss of power to the A Containment Radiation Monitor completed the one of four logic to cause the Containment Radiation Alarm. The ECO was in error. The request had been for breakers 3 and 4 on Instrument Bus 2MA-1. The tags were written for breakers 3 and 4 on Instrument Bus 2MA. Section 8.9.1 required that a qualified operator verify the boundary using controlled documents. This verification was inadequate as evidenced by the wrong breakers being identified. The ECO was returned to the Clearance Center for rework. A Condition Report (CR 97-829) was generated to track the problem.

On April 29, the licensee was making preparations to start draining down the refueling cavity level using the B Low Pressure Safety Injection (LPSI) pump recirculation line to the Refueling Water Tank (RWT). The planned configuration was to have the B Shutdown Cooling (SDC) train in service and to throttle a valve to establish the desired flow rate through the recirculation line to the RWT. In order to make the recirculation path to the RWT available, a boundary modification to the A SDC clearance (2-97-291R) was necessary so that two valves could be untagged.

The boundary modification was executed and the B SDC system was placed in service. Approximately seven minutes after starting the pump, a Senior Nuclear Plant Operator (SNPO) noticed a large amount of water pouring from a drain valve in the pipe penetration room. He immediately notified the control room and the pump was secured, stopping the water flow. The licensee performed a valve lineup and discovered that a vent valve and a drain valve on a test header were left open by the ECO. This flow path had not been detected in the reviews of the boundary modification. The licensee estimated that approximately 500 gallons of water was dumped to the safeguards sump. The inspector reviewed the Refueling Cavity logs for the time of the event. Based on a level change of approximately one inch, the inspector estimated approximately 1800 gallons of water was drained to the sump. A condition report, CR 97-853, was generated to track this problem. Procedure OP 0010122, Revision 68, "In-Plant Clearance Orders" section 8.15.11 required that the review and approval cycle for hanging the new tags "shall be performed in the same manner as the original Clearance Order," that is that the new boundary should be verified by a Reactor Control Operator

consistent with Section 5.5.2.A of the procedure. As exhibited by this unintentional loss of Refueling Cavity level, this verification was inadequate.

These events are examples of failures to follow the ECO procedure and are identified as a violation (VIO 50-389/97-04-01, "Failures to Follow the Equipment Clearance Order Procedure.") This licensee identified violation is being cited due to the numerous examples, the seriousness of the issue, and the apparent ineffectiveness of interim corrective actions per section 6.3.1.3 of the NRC Enforcement Manual.

The inspector discussed the events with personnel in the clearance group. The Senior Reactor Operator (SRO) qualified personnel agreed that there was a large volume of work being processed through the clearance center and that there continued to be scheduling pressures to keep work moving. However, the SROs stated that they felt that they were able to maintain control of the clearance process. Although the schedule pressures were real, they felt that they were not allowing packages to be rushed through. The remainder of the operators in the clearance group generally echoed this evaluation, although some stated that they did feel that there was a large amount of work to complete in a limited amount of time.

The inspector also questioned operators as to the adequacy of the ECO procedure. The consensus opinion was that it was fairly complicated but, would work as written. The inspector also probed several operators knowledge of the procedure and found that the operators understood how the procedure worked. Also, the inspector noted that the operators were frequently interrupted while performing clearance reviews. They were unable to maintain a constant train of thought throughout the review process due to these interruptions.

The inspector discussed the ECO process with several clearance holders and determined that they felt that there were a few problems with the system. First, pre-outage training was not adequate to ensure the procedure was thoroughly understood by the workers. Second, workers did not routinely verify boundaries before starting work. Third, the workers felt that the clearance process took too long. Fourth, the clearance release process was unwieldy, requiring several signatures to complete. Last, the workers felt the boundary modification process was confusing. Last year the licensee performed a major rewrite to the ECO procedure. Although the licensee did perform training at the end of last year on the new procedure, the maintenance personnel performing the work were still getting confused as to the correct type of boundary modification to use.

Licensee management treated these problems as attributable to personnel errors. Immediate corrective actions included stand down meetings with personnel and counseling of individuals directly involved. CRs have been written to identify the root causes of the events, and extra operators were temporarily reassigned to the clearance center until the beginning of fuel reload.

The inspectors have noted an increasing trend in ECO problems over the last several months. Violation 50-335,389/97-01-01, "Failure to Follow the In-Plant Equipment Clearance Orders Procedure" documented a case where a typographical error went undetected through the ECO process resulting in a tag identification number that did not match the component on which it was hung. The corrective actions for the violation included enhancing the procedure to ensure that operators would seek assistance as necessary when verifying equipment clearance boundaries and discussions with licensed and non-licensed operators to emphasize the importance of implementing ECOs with the highest level of accuracy and attention to detail. Non-Cited Violation 50-335/97-03-01, "Failure to Adequately Implement an Equipment Clearance Order," detailed a failure by the licensee to verify the accuracy of an ECO that lead to routing approximately 135 gallons of Volume Control Tank Inventory to a charging pump cubicle floor drain. Again, corrective actions included counseling personnel on the importance of procedural compliance.

On March 17, the licensee identified an increasing trend in ECO problems. This was documented on Condition Report, CR 97-0495. The inspector noted that the identification of the increasing trend was proactive and that an aggressive action to determine the cause of the problems was initiated. A common cause analysis was performed by operations and a preliminary disposition was developed. The licensee determined that the disposition was incomplete and reassigned it to operations on April 14 for further work. The required final disposition of the Condition Report was delayed until May 16. The licensee has been implementing corrective actions as the issue developed.

c. Conclusions

The inspector found that the ECO process was adequate to safely isolate equipment for personnel safety and that operators where knowledgeable of the process and requirements of the procedure. The licensee was proactive in identifying declining trends in clearance procedure adherence. Interim corrective actions have not been effective in correcting the problems; however, the final corrective actions are still being developed. A violation was identified for several examples of problems following the ECO procedure.

02 Operational Status of Facilities and Equipment

02.1 Engineered Safety Feature System Walkdowns (71707)

The inspector walked down accessible portions of the Unit 2 Intake Cooling Water (ICW) system on April 9 and the Unit 2 Component Cooling Water System (CCW) on April 10. Equipment operability, material condition, and housekeeping were acceptable in all cases. Several minor discrepancies were brought to the attention of the licensee and were corrected. The inspectors identified no substantive concerns as a result of these walkdowns.

02.2 Unit 1 Unusual Event and Reactor Shutdown due to Leakage on 1B2 Safety Injection Vent Piping (71707)

a. Inspection Scope

At 2:15 am on April 19, the licensee positively identified a reactor coolant pressure boundary leak occurring from the 1B2 Safety Injection (SI) header. An Unusual Event was declared, and the Unit entered Mode 3 shortly thereafter.

b. Observations and Findings

In the morning of April 17, the licensee refilled the Safety Injection Tanks (SITs) using the 1B High Pressure Safety Injection (HPSI) pump. Following the filling evolution, it was noted that the 1B2 SIT began showing a steady level decrease of approximately 2.5 percent over the next six hours. Also, reactor cavity leakage was noted to increase from .2 gallons per minute (gpm) to .45 gpm. A Reactor Coolant System (RCS) inventory balance performed the following morning indicated that unidentified RCS leakage was 0.09 gpm, consistent with previous readings. The licensee determined that the leak was not reactor coolant.

The licensee performed several troubleshooting activities, including containment walkdowns, in an attempt to determine the source of the water. During one of these walkdowns, water was observed in the 1B2 SI trench. The licensee was unable to determine the source of the water due to ALARA concerns; chemistry samples, however, indicated a high boron concentration. A robot camera was subsequently dispatched behind the biological shield wall to attempt to identify the leakage. The licensee observed leakage coming from the area of a vent valve off of the 1B2 SIT line, upstream of a check valve. Due to piping insulation and limited camera resolution, they were unable to positively identify the type of leakage. A reactor shutdown was initiated at 8:20 pm to allow personnel access to characterize the leakage.

The Assistant Nuclear Plant Supervisor (ANPS) conducted a short brief prior to beginning the downpower. The crew discussed several possible scenarios for the leak from packing leakage which could be readily repaired to an RCS pressure boundary leak which would require a complete shutdown, cooldown, and possibly a draindown to repair. The brief was conducted professionally, and all input from the crew was addressed appropriately. The inspector noted that the licensee planned to maintain reactor power at approximately 10^{-4} percent power. Reactor Engineering (RE) input was incorporated into the plan to allow Xenon buildup to be countered by boron dilution to maintain power constant. The inspector observed good coordination between RE and the operators to control power during the entire evolution.

The generator was removed from the grid at approximately 1:00 am, and power was stabilized at 10^{-4} percent about one hour later. Overall crew performance was well controlled and coordinated. ANPS command and

control function was good although a couple of instances of the ANPS attempting to control too many details of the evolution were noted. A containment entry was made at approximately 2:00 am. The licensee determined that a socket weld leak existed where a vent line met the SI header. The licensee determined that this qualified as a Reactor Coolant Pressure Boundary Leak as defined by 10 CFR 50.2(v) and entered the action statement for Technical Specification 3.4.6.2. The action statement required the plant to be in Mode 3 within one hour and in cold shutdown within the following 30 hours.

A Notice of Unusual Event (NOUE) was declared at 2:18 am. Mode 3 was entered ten minutes later. All notifications were made within the allotted time period. Cold shutdown was reached at approximately 3:15 am the following day.

c. Conclusions

The licensee exhibited conservative decision making to determine the source of leakage inside containment. The shutdown was well controlled and the inspector noted good cooperation between RE and Operations in controlling power while in Mode 2.

02.3 Unexpected Inventory Loss While Placing Unit 1 on Shutdown Cooling (71707)

a. Inspection Scope

While placing the A Shutdown Cooling (SDC) Train in service, the licensee noted a significant pressurizer level drop over a short period. Subsequent investigation by the licensee determined that the loss of inventory was caused by a combination of a void forming in the hot leg suction pipe and a partially open recirculation valve. Thus when the suction valve was opened, part of the Reactor Coolant System (RCS) filled the void creating a water hammer and a portion was diverted to the Refueling Water Storage Tank (RWT).

b. Observations and Findings

On April 19, Unit 1 was cooling down to repair a leaking socket weld in the 1B2 SIT vent line. At approximately 11:20 pm, the B train of SDC was placed in service without incident. An attempt was made to place the A train in service at 11:50 pm by opening the hot leg suction valves. The board Reactor Controls Operator (RCO) noted that pressurizer level decreased about 3 percent in two and one half minutes. The suction valves were shut and the level decrease ceased. The licensee walked down the system for leaks and checked all the levels of the tanks that accepted system relief valve discharge. No leaks or tank level changes were noted.

At 12:30 am, the licensee again attempted to place the A SDC train in service, this time with operators stationed at key locations. Again when the suction valves were opened, the RCO observed pressurizer level

decrease. This time level lowered 3.7 percent in a 70 second period. The Nuclear Watch engineer (NWE) in the 1A Low Pressure Safety Injection (LPSI) pump room heard flow and believed that the 1A SDC suction relief valve had lifted.

The licensee verified the NWE's theory by attempting to place the train in service a third time. During this attempt, 6.2 percent pressurizer level was lost in one minute, with an initial drop of 2.4 percent in the first ten seconds. Local personnel reported water hammer noise, a short duration lift of the suction relief valve, and a pressure spike of 350 psig on a local gage. The suction pressure then stabilized at RCS pressure.

The licensee formed an Event Response Team (ERT) to determine the cause of the event. The ERT determined that approximately 800 to 900 gallons of water was lost from the pressurizer. If all of this water had been relieved to the Hold Up Tanks (HUT), the HUTs' level would have risen by 2 percent. Level only increased approximately 0.1 percent, indicating that the inventory was not relieved to the HUTs.

The ERT surmised that a void had formed in the suction piping since the last use. Hot reactor coolant remained in the pipe when SDC was secured. As the coolant cooled, it contracted and released gases from solution. The A train was built with many local high points in the piping that could trap gases. When the licensee opened the suction valves, the voids collapsed, allowing a water hammer to occur. Unit 1 has had many problems in the past with water hammer occurring while placing SDC in service. This time, the root cause was determined to be inadequate venting of the suction line before placing the SDC loop in service. At the end of the report period, the licensee was revising their SDC procedure to ensure that all piping would be adequately vented before use.

Additional walkdowns by the licensee found the Low Pressure Safety Injection Pump (LPSI) recirculation valve partially open. Four different licensee personnel verified that the recirculation valve was shut before placing the SDC system in service. During the investigation, an operator was able to get two additional turns on the valve using a valve wrench. The licensee planned to disassemble the valve at the next opportunity to determine why it was so difficult to close. This valve remaining open combined with the relief lifting, led the ERT to determine that the loss of inventory was due to refilling the void in the suction piping and recirculating part of the water back to the RWT.

The licensee performed post-walkdowns of the piping to determine if any damage occurred. The inspection revealed no damage. The licensee was planning to upgrade the procedure to allow proper venting of the pipe before placing the SDC system in service.

c. Conclusions

The ERT review of the incident was effective in determining the probable cause of the loss of pressurizer inventory. The licensee corrective actions were appropriate.

02.4 Unit 1 Dropped Control Element Assembly (CEA) (93702)

a. Inspection Scope

The inspector reviewed the operator and maintenance actions taken in response to CEA #66 dropping fully into the Unit 1 core on April 26 and again on May 1.

b. Observations and Findings

On April 26, with the unit at 100 percent power, CEA #66 dropped fully into the core. The Off-Normal procedure was entered and turbine power was reduced to approximately 95 percent to match Tavg to Tref. Technical Specification (TS) 3.1.3.1 Action statement e was entered which required CEA #66 to be within 7.5" of the other CEAs in that group within 60 minutes. The licensee verified that although the rod had dropped it was operable and subsequently restored it to its original position. The reactor was borated to maintain reactor power constant. The cause of the event was not determined.

On May 1, CEA #66 again dropped into the core. The Off-Normal procedure was again entered and the appropriate actions taken. Maintenance was contacted, and following troubleshooting, replaced the timer module and upper gripper power switch. Operability of the CEA was verified and it was returned to its original position. Although the cause of the problem could not be conclusively determined, it is believed to have been resolved with the replacement of the two aforementioned components.

The inspector responded to the site following the April 26 malfunction and verified that the appropriate procedures and TSs were entered.

c. Conclusions

The licensee took the appropriate action in accordance with Off-Normal Procedure 1-0110030 following each event. The correct TS actions were taken. The licensee has planned modifications to be implemented during the next refueling outage which will improve the reliability of the system.

02.5 Unit 2 Fuel Movement - Offload and Reload (71707)

a. Inspection Scope

The inspectors witnessed fuel movement during both the offload and reload. Initial conditions were verified to have been in place prior to fuel movement taking place.

b. Observations and Findings

Unit 2 began offloading fuel from the core on April 24. Fuel reload began on May 6. The inspector verified that the appropriate prerequisites had been completed prior to fuel movement commencing. The following procedures were reviewed and verified to have been satisfactorily completed:

- OP 3200090, "Refueling Operations"
- OP 2-1630024, "Refueling Machine Operation"
- OP 2-1630023, "Fuel Transfer System and L Shaped Door Operation", Revision 13

In addition, the inspectors witnessed fuel movement from the refueling bridge. The two operators on the bridge were deliberate in their actions continuously second checking one another as fuel was being moved. Constant communication was maintained between the control room, the refuel floor, and the FHB. The inspector also monitored the activities from the control room and noted no discrepancies.

c. Conclusions

The inspectors considered fuel handling to have been completed in accordance with approved procedures. The personnel operating the equipment appeared to be very knowledgeable on its use and operated it in a careful and deliberate manner.

08 Miscellaneous Operations Issues

08.1 (Closed) VIO 50-335, 389/95-017-01, Failure to Follow Procedures for Material Controls (92901)

This violation involved a failure to perform the required dedication testing on diodes, a failure to include shelf life requirements, and a failure to comply with the requirements of an engineering "hold". The root causes were determined to be contractor personnel errors, an inadequate inter-department process for transmitting, and verifying the receipt of material, in-stock disposition, and a software programming deficiency which allowed data concerning the engineering evaluation to go unidentified. Corrective actions included additional training for the affected personnel, a review of shelf life requirements, a software correction to the affected plant database, and a review of industry best practice in areas of the dedication testing on diodes and the overall process for identifying and implementing material shelf life requirements.

The inspector reviewed the corrective actions described in the licensee's response letter, dated February 2, 1996, and verified that

the corrective actions were appropriately implemented and completed. Therefore, this item is closed.

08.2 (Closed) VIO 50-335/95-018-02, Failure to Follow Clearance Procedures (92901)

This violation involved a failure to obtain the proper work clearances in accordance with OP 0010122, "In-Plant Equipment Clearance Orders." The root cause of this incident was a failure to follow procedures. The affected personnel involved in the decision to work without proper clearances were counseled. The affected Operations and Maintenance procedures were revised to clarify the requirements associated with opening the vacuum breakers, to provide more specifics with respect to what maintenance activities can be performed without an equipment clearance, and to add a caution statement about the removal of manways. This incident was included in an In-House Events training class.

The inspector reviewed the corrective actions described in the licensee's response letter, dated December 15, 1995, and verified the corrective actions have been completed. Therefore, this item is closed.

08.3 (Closed) VIO 50-389/95-018-03, Failure to Adequately Design and Test the Emergency Diesel Generators (92901)

The subject violation involved an inadequate design of the 2A EDG control logic which did not trip the EDG output breaker on receipt of a CSAS or CIAS signal when paralleled with offsite power. This inadequate design resulted in shifting the governor to the isochronous mode, bypassing all protective relays except overspeed and differential current during integrated safeguards testing on October 12, 1995. This resulted in operating the EDG as a synchronous motor for approximately 45 seconds until the CIAS signal reset. Operation in the isochronous mode while paralleled with offsite power could expose the engine and generator to excessive mechanical stress or electrical overcurrent conditions.

The root cause of the violation was a failure to identify a design deficiency during initial design and testing and to adequately review the revised integrated Safeguards Test procedure prior to implementation on Unit 2. Corrective actions included an inspection and test of the Unit 2A EDG, a review of Unit 1 EDG start logic circuitry to ensure that no similar failure modes existed on Unit 1, a deletion of EDG automatic start on CIAS and CSAS for the Unit 2 EDGs, and a rigorous multi-discipline design review process for future design modifications.

The Inspector verified that the corrective actions described in the licensee's response letter, dated December 15, 1995, to be reasonable and complete. Therefore, this item is closed.

08.4 (Closed) VIO 50-389/95-021-03, Failure to Perform RCP System Boron Surveillance (92901)

This violation involved a failure to take a RCS boron sample as required by Technical Specification. The root cause of this violation was a personnel error by licensed operator who did not strictly adhere to the Administrative Procedure (AP 2-0010125) check sheets which delineate the boron sample surveillance requirements to be performed each shift. The affected licensed operator involved with this event was counselled. Data Sheet 30, "Unscheduled Surveillance Tracking Sheet," was initiated to ensure that the correct sampling frequency was being followed. The event was included in a licensed operator requalification training class.

The inspector reviewed the corrective actions described in the licensee's response letter, dated December 15, 1995, and verified that the implementation of the licensee's corrective actions has been completed. Therefore, this item is closed.

08.5 (Closed) URI 97-03-03, "Excessive Overtime Usage Among Reactor Control Operators" (71707)

St. Lucie IR 97-03 documented the fact that board operators were working excessive amounts of overtime. The overtime was found to be the result of inadequate staffing (the number of licensed operators was inadequate to cover operator illness and leave schedules without the use of overtime). The overtime was found to be concentrated in a number of operators, as opposed to being distributed across the operating staff. During the period of time covered by IR 97-04, the inspector continued to explore the issue.

Regulatory Requirement

St. Lucie Units 1 and 2 Technical Specification 6.2.2.f states, in part, that "adequate shift coverage shall be maintained without routine heavy use of overtime. The objective shall be to have operating personnel work a normal 8 hour day, 40 hour week while the plant is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance or major plant modification, on a temporary basis the following guidelines shall be followed:

1. An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time.

2. An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any 7-day period, all excluding shift turnover time.

3. A break of at least 8 hours should be allowed between work periods, including turnover time.

4. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

The TS also requires that any deviations from the above guidelines be approved by the Plant Manager.

Review of Generic Information

IE Circular 80-02, "Nuclear Power Plant Staff Work Hours," pointed out that studies indicated that, with fatigue, an individual's detection of visual signals deteriorates markedly. The time it takes for a person to make a decision increases and more errors are made. The circular also stated that studies indicated that fatigue results in personnel ignoring some signals because they develop their own subjective standards as to what is important and as they become more fatigued, they ignore more signals.

The circular stated that licensee management was responsible for providing a sufficient number of personnel in the proper physical condition to operate and maintain a plant. The circular further stated that an American Nuclear Society subcommittee was developing criteria for operator work hours and that the NRC was considering issuing requirements for administrative procedures that would control staff overtime. Until such time as requirements were established, the NRC recommended guidance to be applied to all personnel performing safety-related functions. For the most part, the guidance reflected requirements detailed in St. Lucie's TSs, detailed above; however, guidance was also included which stated that plants "...should be staffed and schedules developed to operate such that exceptions [to the guidelines] are not required."

NUREG-0737, "Clarification of TMI Action Plan Requirements," item I.A.1.3, "Shift Manning," presented NRC requirements for administrative procedures controlling overtime. One portion of the document stated that "...the objective of [the administrative procedures] is to operate the plant with the required staff and develop working schedules such that use of overtime is avoided, to the extent practicable [emphasis added]..." The document then delineated overtime guidelines that were, by and large, reflected in the licensee's TSs.

Finally, Generic Letter 82-12, "Nuclear Power Plant Staff Working Hours," stated that licensees were to establish controls to prevent situations where fatigue could reduce the ability of operating personnel to keep the reactor in a safe condition. The controls were to "...focus on shift staffing and the use of overtime--key job-related factors that influence fatigue." The GL went on to state that, to the extent practicable, "...personnel are not assigned to shift duties while in a fatigued condition that could significantly reduce their mental alertness or their decision making capability." The GL then detailed overtime limits similar to those found in TSs.

Identified Condition

A review was performed of overtime utilization for Reactor Controls Operators (RCOs) for 1996. The inspector found that RCOs worked an average of 726 hours of overtime for the year. The lowest number of hours worked was 453.75 hours, the highest was 1009.25 hours. While the inspector did not determine the amount of hours actually worked for each operator (i.e., separating hours paid from hours worked to take sickness and vacation into account), the inspector calculated estimates of total hours worked by adding the hours of overtime paid to an assumed work schedule of 49 weeks of 40 hour duration each for the year. The result was an average of 2,686 hours, with a low value of 2413.75 hours and a high value of 2969.25 hours.

The inspector reviewed overtime usage for the period running from December 12, 1996, through March 14, 1997. The inspector's findings are summarized in the following table.

From	To	Board RCO Overtime Hours	Number of RCOs Exceeding 20 Hours of Overtime	Number of RCOs exceeding 30 Hours of Overtime	Maximum Number of Overtime Hours Worked by an RCO
12/7/96	12/20/96	261	5	2	42.5
12/21/96	1/3/97	574.25	15	5	71
1/4/97	1/17/97	313.5	4	0	29
1/18/97	1/31/97	613.5	14	9	66.5
2/1/97	2/14/97	322.5	6	1	35
2/15/97	2/28/97	305.5	7	2	47.5
3/1/97	3/14/97	623.75	17	12	56.5

On March 15, the licensee chose to implement 12 hour shifts to alleviate the need to force individual operators to accept overtime on case-by-case bases. In doing so, the operators were collapsed into 2 watch sections, one working days and one working nights. This leveled overtime usage across all operators and bolstered shift numbers such that a shift became "self-relieving;" that is, if an operator took time off from work, another operator on his crew could fill in for him. Because the 12 hour scheme required placing all reactor operators onto two watch sections, the schedule required that operators work 5 day on, two day off schedules. This resulted in all reactor operators not on leave working nominal 60 hour weeks. This schedule persisted until April 14, when operators began working a 6 day, 12 hour, shift schedule to support the Unit 2 outage.

The inspector, in conjunction with NRC Regional staff and the NRR Human Factors Branch, concluded that this level of overtime constituted a "heavy" use of overtime for routine operations. The determination was based, largely, on a "reasonable man" approach to the overtime data provided by the licensee. The inspector continued to review available information in an attempt to find additional support for this conclusion.

Review of Available Information - "Heavy Use"

The inspector reviewed NUREG/CR-4248, "Recommendations for NRC Policy on Shift Scheduling and Overtime at Nuclear Power Plants," to determine whether the reasonable man approached described above was supported by scientific data. The document proposed limits for hours of work, discussed bases for the limits, and presented recommendations which resulted from an expert panel of scientists and medical personnel from the field of human performance.

The NUREG-proposed limits on hours of work begin with admonitions against the routine heavy use of overtime, similar to the existing TS (section 1.0). The NUREG then recommends that nuclear power plants adopt a routine 8 hour per day shift schedule with limitations detailed in Table 1 (NUREG section 1.0, page 1.4).

The NUREG also provided guidelines for 12 hour shifts, but recommended that prior NRC approval be obtained prior to initiating 12 hour shifts. Criteria to be employed by NRC in assessing the acceptability of 12 hour shifts are also provided and are detailed in Table 1 (NUREG section 1.0, page 1.4).

For cases in which overtime is required to be worked, the NUREG recommended limitations which are detailed in Table 2 (NUREG section 1.0, Table 1.1). The NUREG recommended that the limitations be the maximum allowable without prior Plant Manager approval. These limits were provided to cover "problems during operation" (defined in section 2.1 as unexpected absences of operators due to illness, injury, etc. and the "temporary" lack of an adequate number of operators) and extended shutdowns.

The allowance to exceed guidelines with Plant Manager approval was provided to cover "unusual circumstances," which was defined in section 2.1 as circumstances other than extended shutdowns (the NUREG states in section 2.2.3 that an extended outage may not be considered as an "unusual circumstance"). The NUREG then presented a separate set of limitations which, even with Plant Manager approval, should require NRC approval to exceed. These limitations were to cover what the NUREG defines as "very unusual circumstances," which were defined as being states of declared emergencies. Those limits are detailed in Table 2 (NUREG section 1.0, Table 1.1).

Later in the NUREG, the results of an expert panel, convened to offer suggestions on the subject of limits on hours, is presented. The panel was comprised of M.D.s and Ph.D.s from the fields of military and private sector human performance. The panel recommended a policy for routine operations detailed in Table 1 (Appendix A of the NUREG). For conditions involving overtime, a policy, detailed in Table 2, was provided.

Table 1
Limits for Routine Operations

Source	Recommendations
St. Lucie TS	8 hour days, 40 hour weeks
NUREG/CR-4248 recommendations for 8 hour schedules	8 hour days, 40 hour weeks, subject to: ● A maximum of 7 consecutive days of work ● A maximum of 21 consecutive days of work in 4 weeks ● At least 2 consecutive days off in 9 consecutive days ● Night shifts followed by 2 consecutive days off
NUREG/CR-4248 recommendations for 12 hour schedules	12 hour days, subject to: ● A maximum of 4 consecutive days of work ● Schedules arranged in 2-on/2-off, 3-on/3-off, or 4-on/4-off work periods ● Satisfactory SALP ratings ● Unexpected absences covered without individuals working greater than 12 hours ● Round trip commutes for personnel less than 2.5 hours
NUREG/CR-4248 Expert Panel recommendations*	● Not more than 9 hours per day ● Not more than 6 days worked per 8 day period ● An average of 40 hours per week when averaged over 1 month ● Selective NRC approval for 12 hour schedules

* While St. Lucie TS and the NUREG recommendations exclude turnover time from limitations, the expert panel recommendations include turnover time.

Table 2
Limits for Overtime

Source	Recommendations	
St. Lucie TS	• A maximum of 12 hours in a 24 hour period • A maximum of 24 hours in a 48 hour period • A maximum of 72 hours in a 7 day period • Overtime assigned on an individual, rather than shift, basis • Plant General Manager approval for deviations from these guidelines	
NUREG/CR-4248 recommendations	Without Plant General Manager Approval	With Plant General Manager Approval**
	• A maximum of 12 hours in a 24 hour period • A maximum of 24 hours in a 48 hour period • A maximum of 60 hours in a 7 day period • A maximum of 112 hours in a 14 day period • A maximum of 2260 hours in one year	• A maximum of 72 hours in a 7 day period • A maximum of 132 hours in a 14 day period • A maximum of 228 hours in a 28 day period • A maximum of 2300 hours in one year
NUREG/CR-4248 Expert Panel recommendations*	• A maximum of 13 hours in a 24 hour period for day and evening shifts • A maximum of 9 hours in a 24 hour period for night shifts • A maximum of 22 hours in a 48 hour period • A maximum of 123 hours in a 14 day period • A maximum of 213 hours in a one month period • A maximum of 2400 hours in one year • Overtime considered on an individual basis • NRC Notification for exceedences	

* While St. Lucie TS and the NUREG recommendations exclude turnover time from limitations, the expert panel recommendations include turnover time.
** For declared emergencies and similar situations.

The data provided in this section, to this point, was presented to establish a baseline for determining whether the licensee's use of operator overtime is heavy when compared to recommendations provided by professionals in the field of human performance.

As stated above, the inspector reviewed overtime hours worked by the 23 RCOs available to the licensee at the end of 1996 (the review did not include hours worked by two RCOs which are no longer employed by the licensee). For all RCOs, the total hours worked exceeded all annual recommendations (those provided in the base recommendation for overtime not requiring Plant General Manager approval, those requiring Plant General Manager approval, and those provided by the expert panel). As these data covered the entire calendar year, this result would tend to confirm the fact that the use of heavy overtime has been chronic (routine).

The inspector also reviewed overtime usage for the first 3 months of 1997. Table 3 represents the results. From the data (which involve 8 hour shifts), it is clear that the licensee's use of overtime under an 8 hour per day schedule has required (and will require) routinely exceeding guidelines recommended by the NUREG.

Table 3
RCO Overtime Usage for the First Three Months of 1997

Guideline	Number of Occurrences of Exceeding Guideline	Number of Operators Exceeding Guideline More Than 1 Time
A maximum of 112 hours in 14 days	25	8
A maximum of 123 hours in 14 days	9	1
A maximum of 213 hours in one month	14	5

Additionally, by examining the number of operators exceeding the guidelines more than once, it would appear that the occurrences are somewhat clustered about a small subset of operators. In point of fact, a review of the raw data reveals that the bulk of the exceedences occur in a relatively small population, as depicted in Table 4. The distribution resulted in approximately 80% (32) of the exceedences being worked by approximately 35% of the operators (8 operators).

Table 4
Distribution of Overtime Among RCOs

Number of Times Any NUREG Recommendation was Exceeded	Number of Operators Involved
0	9
1	5
2	1

3	4
4	2
5	1
6	0
7	1

By most standards presented in the NUREG, the licensee's use of overtime for routine plant operations exceeded that which was recommended. In some cases, the licensee's use of overtime for routine operation even exceeded recommendations for extended periods of shutdown. The inspector concluded that this data would tend to support the reasonable man conclusion that the licensee has been making heavy use of overtime for RCOs.

As the licensee stated that the condition could not be alleviated without additional licensed reactor operators, and since no new operators were anticipated to be qualified until October, 1997, the inspector concluded that the heavy use of overtime was "routine."

In considering the question of whether the condition was unforeseen, the inspector noted that the licensee's predicament was largely the result of not having placed operator candidates into the training process approximately 2 years previous, coupled with transfers, promotions, and minor attrition. The inspector found that a number of active and inactive licensed operators were being utilized by the licensee in other organizations on site, such as outage planning, training, procedure writing, clearance preparation, and operator shift scheduling. Given that the licensee elected to reduce the number of operators being trained, elected to promote operators out of board operating positions, and elected to utilize qualified, licensed, operators in other capacities, the inspector concluded that the condition was not unforeseen.

As it was concluded that the use of operator overtime was routine, heavy, and not unforeseen, the NRC concluded that the subject TS was violated, both prior to and after the implementation of 12 hour shifts. The violation would not apply to outage periods, which are specifically addressed (in terms of overtime guidelines) by the TS.

Conclusion

The inspector concluded that the licensee's use of RCO overtime for routine operations was heavy and that the need for the overtime was not unforeseen. Consequently, the licensee was found to be in violation of TS 6.2.2.f (VIO 335,389/97-04-02, "Routine Use of Heavy Operator Overtime"). The inspector concluded that the licensee's shortage of operators was the result of poor planning in the past, combined with promotions of individuals out of the Operations organization. The

overtime was considered to have been preventable, had management focused on the issue. This URI is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Main Steam Safety Valve Testing (61726)

a. Inspection Scope

On April 13, the licensee reduced power on Unit 2 to approximately 80 percent to allow setpoint testing of the Main Steam Safety Valve (MSSVs). The inspector observed portions of the test preparation, testing, and reviewed the post-test data.

b. Observation and Findings

MSSV testing was performed in Mode 1 in accordance with Procedure 2-OSP-08.1, Revision 2, "Main Steam Safety Valve Setpoint Surveillance." The inspector reviewed the procedure to ensure compliance with Technical Specification (TS) 3.7.1.1. The inspector noted that the licensee's procedure was more restrictive than the TS. The TS required lift setpoint range was ±1 percent, while the procedure required ±0.5 percent. The licensee explained that this was a holdover from earlier in the site's history when they had problems with the valves leaking by their seat. Later, the licensee changed the procedure to allow the full TS range as acceptance criteria. The inspector verified that the change was performed in accordance with licensee procedures.

The inspector verified that all Measuring and Test Equipment (M&TE) was properly calibrated and checked out. The inspector also verified that the High Power Trip Setpoints had been adjusted as required by the procedure. The inspector found the test preparations satisfactory.

The inspector observed portions of the test in progress. Proper communications were being employed by all personnel. Verbatim compliance to the procedure was observed. The inspector noted that the data was being accurately entered into the test procedure.

On May 8, the inspector reviewed the test data. All data were legibly entered and were complete. The test data met all acceptance criteria. The inspector did note that the original procedure did not have a copy of the revised acceptance data in the package. The licensee corrected the deficiency. The inspector verified that the surveillance schedule was met. Procedure QI 11-PR/PSL-7, Revision 9, "Control of Code Safety and Relief Valves" required that at least 20 percent of the valves are tested, on average, each year, this would require one third to be tested each outage. The licensee satisfactorily tested 7 of 16 valves this outage.

c. Conclusions

The licensee's performance of the setpoint surveillance on the MSSVs was satisfactory.

M1.2 Upper Guide Structure Removal (62707,71750)

a. Inspection Scope

On April 23, the licensee attempted to lift the Upper Guide Structure (UGS) from the reactor vessel to allow fuel removal. Upon the initial lift, containment radiation levels rose markedly and a containment high radiation alarm occurred on one channel causing the Containment Evacuation Alarm to actuate. The inspector observed the initial lift, and recovery plan formulation.

b. Observations and Findings

On April 23, the license was lifting the UGS per General Maintenance Procedure 2-M-0036, Revision 27, "Reactor Vessel Maintenance Sequence of Operations." The inspector verified that all requirements for the heavy load lift were met, including adequate supervision and support. Refueling cavity water level was approximately 56.1 feet, which met the requirements of Procedure OP 2-1600024, Revision 26, "Filling and Draining the Refueling Canal and Cavity." The licensee treated the lift of the UGS as a core alteration, so containment integrity was established.

As the UGS rig was lifted, part of the Incore Instrumentation guide tube cluster broke the surface of the water. Containment Radiation Monitor MD alarmed at an indicated dose rate of 90 mr/hr reaching a maximum of 290 mr/hr before lift was halted. When the radiation alarm sounded, this activated the Containment Evacuation Alarm. All personnel evacuated the Containment except those on the refueling deck. They were directed behind the Steam Generator missile shields for shielding. The other three channels reached a maximum of approximately 30 mr/hr. This would be the expected result of a highly activated particle breaking the surface. The MB and MC detectors were shielded by the steam generators, and the MA detector was the furthest away. The Assistant Nuclear Plant Supervisor ordered the UGS to be lowered back into the water. Radiation levels returned to normal.

The licensee then formulated a plan to move the UGS while maintaining personnel protection. The licensee determined that the only thing capable of producing such high radiation levels, several hundred rem per hour, were broken incore instruments. Two major paths were discussed. First, the licensee could attempt to push the incores down into the tubes to ensure they remained submerged during the lift. Second, they could evacuate all personnel from containment, shield the necessary personnel inside containment, and perform the lift using remote viewing cameras to observe. Due to concerns with dropping the incores into the vessel if the first option was attempted, the second option was chosen.

At approximately 5:00 pm that night, all personnel, except the lift team, were removed from containment. The lift team, except the crane operator, remained behind the pressurizer shielding for the entire lift. The UGS was lifted. Radiation Monitor MD alarmed again and eventually rose to approximately 1700 mr/hr. As the UGS was moved to its storage position, monitor MA alarmed. The two radiation monitors alarming caused a Containment Isolation, as expected. Control Room personnel verified that all Containment Isolation systems functioned as expected. The load was placed in its stand in the refueling cavity and radiation levels returned to normal. The containment isolation signal was reset and systems were restored. The maximum dose received by anyone in containment was 34 millirem to the crane operator.

Later, the licensee working with ABB determined that there were three individual broken incores in the UGS. One was removed from the structure, and the other two were inserted toward the bottom of the thimble tubes.

c. Conclusions

The actual lift of the UGS was performed under the proper maintenance controls. The licensee's recovery actions to complete the lift safely after discovering the hot particles was good. Coordination between Operations, Maintenance, and Health Physics was judged to be excellent.

M1.3 Diesel Generator 2A Relay and Socket Replacement (62707)

a. Inspection Scope

From April 20 to April 29, the inspectors observed maintenance personnel installing and testing new relays in the control panels for the 2A Emergency Diesel Generators (EDG). The relays control the start and operation of the EDG. The new relays were of a different design than those they were replacing due to known failure modes of the old style relays. The inspection consisted of document reviews and field verification of the work performed.

b. Observations and Findings

The work activity was being conducted in accordance with Work Order 96027011 01 and PC/M 96-137M. The inspector observed a maintenance worker de-terminate wiring, remove old relays, install new relays, and re-terminate wiring. The work was verified to have been performed as directed by the work documents. Drawings used for wire terminations were verified to be correct and of the proper revision as described in the modification package. Independent verifications were observed to occur properly. This was a complex activity involving a large number of wire lifts inside a small panel. Discussions with the individuals performing this activity indicated a high level of knowledge regarding the work being performed.

The testing of the control panels was performed in accordance with PC/M 137-296M. The inspector spot verified that the procedure was testing the circuits as described by verifying the step sequencing with the electrical diagrams. No discrepancies were noted. The inspector observed performance of portions of the test. The System and Component Engineer (SCE) started in the role of the test director. The SCE coordinated activities between Operations and Maintenance. Overall conduct of the testing was good. The inspector found all personnel involved in the testing to be thoroughly knowledgeable about their work.

c. Conclusions

The inspector concluded that this was a well-coordinated complex activity. The maintenance personnel performing the work were extremely knowledgeable about the activity. Although the work area was located inside a small cabinet containing other electrical components, the workers were careful and deliberate in their actions not to affect other components.

M1.4 Fuel Handling Building Ventilation System Periodic Test-Unit 2 (61726)

a. Inspection Scope

On April 21, 1997, the inspector observed portions of the performance of Operating Procedure 2-1600025, Revision 9, "Fuel Handling Building Ventilation System - Periodic Test.

b. Observations and Findings

The purpose of the procedure was to verify that each train of the Shield Building Ventilation System could maintain the spent fuel storage pool area at a negative pressure of at least 0.125 inches water and would isolate the fuel storage pool area upon receipt of a high radiation signal. Performance of the surveillance required close coordination between two I&C technicians, a Senior Reactor Operator, a Nuclear Plant Operator, and the test director. The inspector noted that test director controlled the activity and ensured each participant understand how to perform each step and what the expected outcome would be. The inspector verified compliance with the procedure and satisfactory performance of the portions observed.

c. Conclusions

The licensee performed this evolution in a controlled manner. The participants had a complete understanding of the expected system response during performance of the surveillance. Good communication was observed by the inspector.

M1.5 Inservice Inspection (ISI) - Unit 1 (73753)

a. Inspection Scope

The inspector reviewed program plans, procedures, and documentation related to the conduct of ISI Inspection during the Spring 1997, Unit 2 Outage. Results were compared with the ASME Section XI Code of Record.

b. Observations and Findings

Pressure Boundary ISI

St. Lucie Unit 2 began commercial operation on August 8, 1983. The second 10-year, ISI interval began on August 8, 1993, with the Code of record established as ASME Section XI, 1989 Edition, with no addenda. With the 10-year, ISI interval divided into three inspection periods, the second inspection period started on August 8, 1996. This outage was the first outage in the second period of the inspection interval.

The inspector observed and reviewed the following ISI activities:

Component/Weld	Examination	Comment
Safety Injection Piping Weld SI-112-FW-7	Liquid Penetrant	Five linear indications in the piping adjacent to weld. CR# 97-0836 dated April 28, 1997. (Piping observed during containment walk-through inspection May 1, 1997)
Main Feedwater Piping Weld BF-14-SW-P3	Ultrasonic Examination	Observed UT inspection of both Feedwater welds. The ...SW-P3 weld is inside of the containment
Main Feedwater Piping Weld BF-14-FW-2	Ultrasonic Examination	Penetration; the ...FW-2 weld is the connection of the Feedwater piping to the penetration process pipe.
Safety Injection Piping SI-110-8A-SW1	Liquid Penetrant	Observed Penetrant application, developer application and evaluation techniques.
Reactor Coolant Loop: Pump 2A2 Outlet Weld RC115-5 Weld RC 115-701-771	Ultrasonic Examination	Observed partial calibration of UT instrument, (Final Calibration check prior to examination) and first part of inspection scans.

The inspector also reviewed about 30 documentation packages for completed inspections. These packages were examined to compare completed examination coverage with planned examinations; and for completeness of the individual records. One of the documentation

packages reviewed was a surface (liquid penetrant) examination of weld SI-112-FW-7, discussed below.

On April 28, 1997, ISI surface examinations identified a group of five rejectable, linear indications in base material adjacent to weld No. SI-112-FW-7. The indications were located very near "top-dead-center" of the horizontal run of the process piping of containment penetration No. 37. This weld, SI-112-FW-7, is the weld that connects six-inch diameter Safety Injection piping to the process piping of containment penetration No. 37. Condition Report No. 97-0836 dated April 28, 1997, was written to document these indications and the corrective actions.

During a walk-through inspection of the containment on May 1, 1997, the inspector reviewed the location of SI-112-FW-7 to determine if there could be a source of contamination from above the weld that might result in the surface indications noted above. Based on this inspection, the inspector concluded that the source of the contaminant that resulted in the surface indications was most likely the original installation of the insulation on the piping.

Containment ISI

Effective September 9, 1996, 10 CFR 50.55a, was amended to include the requirements of ASME B&PV Code, Section XI, Subsections IWE and IWL 1992 Edition, with 1992 Addenda. Subsections IWE and IWL provide ISI requirements for concrete containments, steel containments, and steel liners for concrete containments. The amendment to the rule provided a five-year period, until September 9, 2001, before full implementation of Subsections IWE and IWL. In correspondence with the industry, (November 6, 1996, letter to Alex Marion, Nuclear Energy Institute from Gus Lainas, Office of Nuclear Reactor Regulation, concerning "Implementation of Containment Inspection Rule") NRC provided a Staff position that, in response to deficiencies noted prior to the full implementation of IWE and IWL, repair and replacement activities must be conducted in accordance with those subsections.

The licensee issued Revision 8 of Examination Procedure NDE 4.3, "Component, Support &.Inspection Visual Examination VT-3" in April 1997, to include inspection requirements for VT-3 examination of Class MC Metallic Containment Building surfaces, penetrations, and attachments.

On May 1, 1997, the inspector accompanied two licensee VT-3 inspectors during an inspection of the condition of the coatings on surfaces, penetrations, and attachments on the inside of the containment building. With the exception of minor spots where the coating had been rubbed or scraped by portable equipment such as scaffolds, etc., the containment coating appeared to be in very good condition. The one notable exception was the joint compound between the concrete floor and the containment wall at the lowest level of the containment. The joint compound appeared to be brittle and had cracked. The licensee inspectors noted the condition, and initiated a condition report which

should result in the joint compound being replaced during the next refueling outage.

Repair and Replacement

Unit 1

On April 19, 1997, Unit 1 was shut down due to a socket weld leak where a one-inch diameter vent line tied into the 12" diameter Safety Injection Header. (The connection to the SI Header consisted of a sock-o-let connector welded to the 12" diameter header, with the one-inch vent line socket welded to the connector. The connection between the one-inch vent line and the sock-o-let had been welded during the 1996 refueling outage in association with the replacement of vent valve V3815. Condition Report No. 97-0713 was generated to document the problem and subsequent repair.

On April 28, 1997, the inspector reviewed the licensee's failure analysis report for the Safety Injection System socket weld failure. The failure analysis was conducted by the licensee's Metallurgical Laboratory Personnel and reported by Inter-Office Correspondence, MET-97-128, dated April 27, 1997. This report showed that the failure occurred as a circumferentially oriented crack located at the sock-o-let side of the toe of the weld. The report stated that the crack initiation appeared to be similar to hot cracking and lack of fusion noted in previous failures at St. Lucie when base materials which had seen boric acid service had been re-welded.

The failure analysis report concluded that the cause of the failure was most likely the result of incomplete cleaning of the sock-o-let connector prior to the welding of the socket weld connection. As stated in the failure analysis report, the licensee's Weld Control Manual provides guidelines for mechanical and chemical cleaning of boric acid residue from base materials that are to be re-welded. The report also stated that plant chemical control procedures made chemical cleaning of the subject weld fitting impracticable.

Based on the morphology of the crack surfaces shown in the report photographs, the inspector was in agreement with the licensee's conclusions concerning the type of failure.

Common

During a walk-through inspection of the site, the inspector noted that the main fire protection pumps and motors appeared to have a thick coating of red paint. The inspector was concerned about the affect that this coating of paint would have on the heat dissipation capability of the induction motors for the pumps. During a discussion with the licensee Fire Protection personnel, the inspector learned that the two pumps had been rebuilt during the past year when the pump casings were replaced.

The inspector reviewed the work packages for the 1B fire pump which was re-built in October 1996. The review was conducted to ascertain what types of problems were associated with replacing the pump casing on a pump that had been in service for approximately 20 years.

The documentation showed that some minor alignment problems were encountered when the new casing was installed. Mechanics' notes showed that the use of shims under the pump feet were used to align inlet and outlet flanges, while strongbacks and heat to ≈500°F were used to pull the coupling hubs to within the required proximity.

Discussions were held with the licensee's coatings specialist concerning the thickness and heat transfer capability of the paint on the induction motors. The inspector was shown that the licensee's program limited the thickness of coatings on things like motors to the thickness that was originally provided by the manufacturer.

During discussions with the licensee fire protection personnel, the inspector learned that the fire pumps had recently been run continuously during the time that it took the licensee to test the entire fire hydrant system. This testing of the fire system was viewed as an additional final test for the replacement pump casings.

c. Conclusions

The pressure boundary ISI activities were well organized and work activities observed were conducted in accordance with approved procedures. Containment surveillance procedures had documented acknowledgement of recent changes to NRC regulations

Failure analysis of Unit 1 Safety Injection System socket weld connection was very well done.

Replacement of pump casings on the site fire protection pumps appears to have been a successful operation.

M1.6 <u>Steam Generator (SG) Inspection - Unit 2 (50002)</u>

a. Inspection Scope

Through discussions with personnel and review of documentation, the inspector reviewed the Eddy Current (ET) inspection of the Unit 2 SGs.

b. Observations and Findings

The licensee conducted 100 percent Bobbin Coil examination of the tubes in the Unit 2 SGs; along with 100 percent MRPC examination of the hot-leg top-of-tube-sheet (HL TTS) area. After completion of the planned and supplemental eddy current examinations, the licensee conducted in-situ pressure testing of the five tubes with the largest HL TTS circumferential cracks, and five tubes with the largest axial cracks.

The inspector reviewed procedures for activities involved with the eddy current testing, In-Situ pressure testing, and plugging of the Steam Generator tubes. Procedures reviewed included the following:

Procedure Number	Revision/Date	Title
ENG-IS-1.2	Revision 1 April 1997	The Receipt Inspection of Nondestructive Examination Equipment and Materials
IS-DT-001	Revision 0 April 1997	Control of Eddy Current Probes Used for Steam Generator Examinations
STD-400-166	Revision 5 April 3, 1997	Procedure for the Checkout and Operation of the Steam Generator Tube In-Situ Pressure Test Tool
Traveler No. PSL-007	Revision 4 March 28, 1997	In-Situ Pressure Testing
Traveler No. PSL-001	Revision 7 December 2, 1996	Mechanical Tube Plugging Steam Generator With 0.750" O.D. 0.048" Wall Tubes Including Provisions for Restricted Access Corner Areas
Traveler No. PSL-010	Revision 1 December 3, 1996	Mechanical Tube Plugging and Stabilizer Installation Steam Generator With 0.750" O.D. 0.048" Wall Tubes
STD-100-219	Revision 1 April 4, 1997	Technical Operating Procedure Interpretation of Torque Trace Charts Steam Generator Mechanical Tube Plugging
STD-410-081	Revision 5 August 21, 1996	Remote Mechanical Tube Plug Installation Utilizing Computerized Control System

The inspector observed the in-situ pressure testing of all ten of the tubes selected from the licensee's remote video station. Pressure testing was conducted in four pressure steps, with a one-minute hold at each pressure to look for leaks. The four pressures were: for circumferential cracks: 1850 psi, 3150 psi, 5450 psi, and 6050 psi; for axial cracks: 1650 psi, 2850 psi, 4900 psi; and 5500 psi. There were no tube leaks found during the in-situ pressure testing.

The inspector also observed a portion of the tube plugging operations from that location. Steps observed included the insertion of plugs, pressure rolling of the plugs, and comparison of the recorded roll pressure profile to the required pressure profile specified in the plugging procedure.

c. Conclusions

The licensee's program for inspection of SGs appears to be well managed and conducted in a conservative manner. The procedures reviewed were found to be adequate for the intended operations. In-situ pressure testing and plugging operations were conducted in a professional manner.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Housekeeping and Foreign Material Exclusion Control (62707, 71707)

a. Inspection Scope

During plant walkdowns housekeeping and foreign material exclusion (FME) controls were monitored on both the operating and shutdown units.

b. Observations and Findings

During routine tours of both the radiologically controlled area (RCA) and the Unit 2 containment building the inspector noted several instances of poor housekeeping and FME control. On April 22, while on the Unit 2 refueling floor, the inspectors noted an individual exit the FME zone and reenter without informing the FME monitor. The monitor stopped the individual and ascertained that he was in fact already signed in on the FME log. The inspector noted that the individual was wearing a safety harness and upon reviewing the FME log found that he had not logged this item in prior to taking it into the FME zone. The FME monitor questioned the individual and determined that he had gotten the harness from inside the zone after someone else brought it in. The FME monitor stated that she thought this was reasonable, however, without inventorying the entire FME zone it would be impossible to determine with certainty. On April 23, while touring the Unit 2 Fuel Handling Building (FHB), the inspector observed some individuals remove loose articles from their pockets and tape their badge to their chest prior to entering the Spent Fuel Pool area. However, others, were observed not taking any precautions at all. The inspector questioned if the area was an FME zone and was informed that it was. Although there was an FME log there was not an FME monitor present. The inspector reviewed the licensees procedure for FME control, QI 13-PR/PSL-2, "Housekeeping and Cleanliness Control Methods", Revision 29, and noted that it did not require a monitor to be posted in the FHB.

The inspector discussed these observations with licensee management. In addition, licensee management conducted tours of the FHB and Unit 2 containment and found other similar weaknesses in the FME controls. In response, training was conducted with the FME monitors which outlined their responsibility and authority regarding FME. Additionally, a barrier was placed in the FHB to form an FME zone and a monitor was assigned to log personnel and equipment in and out of the zone. Following institution of these corrective actions the inspectors noted a marked improvement in FME control.

c. Conclusions

At the beginning of the Unit 2 refueling outage the inspectors and the licensee identified several instances of less than adequate FME control. The licensee instituted corrective actions and by the end of the report period the inspectors noticed much improvement.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Spent Fuel Pool Full Core Off-Load Evaluation and Implementation (37551)

a. Inspection Scope

The Inspector reviewed the licensee's calculation to allow a full core off-load of Unit 2, and the implementation of the initial conditions into the appropriate operating procedures.

b. Observations and Findings

The inspector reviewed calculation number MECH-0088, Revision 0, "Transient Temperature of Spent Fuel Pool Following Full Core Off-load," prepared by Sargent & Lundy for the licensee. The inspector also verified that the appropriate data and plant restrictions were properly relocated to the Safety Analysis, PSL-ENG-SENS-97-006, Revision 0, "Safety Analysis, Routine Performance of Full Core Refueling Off-loads, St. Lucie Nuclear Plant, Unit 2" and the unit's implementing procedures.

The calculation states several assumptions:

- Spent fuel pool pump losses add to the heat in the spent fuel pool
- The spent fuel pool water is assumed to be pure water for the purposes of heat transfer calculations
- The decay heat from the spent fuel discharged during previous outages is assumed to remain constant
- No makeup water is available
- Spent fuel pool water density and specific heat remain constant
- Spent fuel pool water is well mixed and no temperature stratifications exist
- Heat transfer due to convection from the pool surface and conduction through the pool walls is neglected
- Evaporative heat removal is based on the Pauker equation
- Ambient air pressure is assumed to be 14.696 psia

- The pool liner is ignored in determining the pool's thermal capacitance as is the stainless steel, uranium dioxide and zircaloy cladding associated with the spent fuel

The calculation was performed several times varying different parameters (spent fuel pool pump flow, Component Cooling Water (CCW) flow, and CCW inlet temperature) to determine maximum fuel pool temperatures. The calculation concluded that the spent fuel pool cooling system could maintain temperature less than 140 F.

The licensee performed a safety evaluation for the cycle nine defueling to document that an unreviewed safety question did not exist for the cycle nine full core offload and future full core off-loads. The evaluation stated that the calculation discussed above demonstrated that the fuel pool temperature would remain less than 140 F if CCW inlet temperature remained less than 95 F. The evaluation also required that if one fuel pool heat exchanger was in service, CCW flow must be maintained greater than 3560 gpm, fuel movement should be secured if fuel pool temperature exceeded 136 F, and both fuel pool cooling pumps should be operated unless one needed to be secured to aid in visibility during fuel assembly placement. This is not fully in agreement with the data provided by the calculation. In cases where CCW temperature was required to be less than 95 F, the calculation assumed that one spent fuel pump was running. The calculation that assumed two spent fuel pumps running had a minimum CCW temperature of 100 F. The inspector did note that the evaluation used conservative values from both cases.

The inspector reviewed Procedures OP 2-0350020, Revision 22, "Fuel Pool Cooling and Purification System - Normal Operation" and OP-1600023, Revision 49, "Refueling Sequencing Guidelines", to determine if the procedures correlated with the guidance given by the safety evaluation. "Refueling Sequencing Guidelines", step 8.16, generally incorporated the directions from the safety evaluation correctly. However step 8.16.4 unduly restricted the plant by requiring "CCW Flow to the in-service (emphasis added) Fuel Pool Heat Exchanger is greater than or equal to 3560 GPM." Neither the original calculation nor the safety evaluation required only one heat exchanger to be used. In fact, OP-2-0350020 stated that CCW should be lined up in accordance with OP-0310020, "Component Cooling Water - Normal Operation." This required that the maximum flow through the heat exchangers remain less than 3650 gpm. Therefore, the two procedures only allowed a 90 gpm band to operate the heat exchangers.

c. Conclusions

Engineering accurately reflected the output of the full core off-loading calculation into its cycle nine refueling outage safety analysis. The licensee also transferred all vital information from the safety analysis into operating procedures, although the procedures, as written, were more restrictive than necessary.

E2.2 Engineered Safeguards Test Equipment Failure (37551)

a. Inspection Scope

On April 15, the licensee was performing a test of the A train Engineered Safeguards (ESF) equipment response to a simultaneous Loss of Offsite Power (LOOP), Safety Injection Actuation Signal (SIAS), Containment Isolation Actuation Signal (CIAS), and an Auxiliary Feed Actuation Signal (AFAS). Several major pieces of equipment did not respond as expected and the test was secured. The inspector reviewed the test results and the licensee's efforts to determine the causes of the failures and their corrective actions.

b. Observations and Findings

The licensee had originally planned to perform section 8.4 of Procedure OP 2-0400050, Revision 22, "Periodic Test of the Engineered Safety Features," at the beginning of the outage to verify that the ESF systems operated as expected. At 2:44 a.m. on April 15, the licensee initiated the test by opening the 2A Startup Transformer feeder breaker to the 2A2 4160 volt bus. The 2A Emergency Diesel Generator (EDG) started and the EDG output breaker restored power to the 2A3 4160 volt bus nine seconds later and load sequencing began.

The 2A Low Pressure Safety Injection (LPSI) pump started as expected, but then tripped after nine seconds on thermal overload. The licensee's initial investigation determined that there was no pump shaft rotation. The pump energized, but flow did not increase and motor amps rose to locked shaft levels. Just prior to the test, the licensee had been using the 2A LPSI pump for Shutdown Cooling (SDC). No problems were noted during operation. The licensee decided to disassemble the pump and replace the motor. They inspected the pump shaft, the motor, and the suction piping for foreign material. No apparent cause of the failure could be determined. The motor has been sent to the vendor for analysis. The final root cause analysis had not yet been completed at the end of the report period.

The 2A1 Safety Injection Tank (SIT) isolation valve failed to stroke and its breaker tripped open. At the end of the report period, the root cause evaluation was still open. Some of the potential causes that the licensee was investigating included pressure locking and mechanical gate binding.

The 2A Auxiliary Feedwater (AFW) pump failed to start at its loading step, 30 seconds into the load sequencing. Approximately 50 minutes later the pump started unexpectedly. The licensee performed a root cause analysis for the failure. Potential causes included failed relays, failed contacts, a loose jumper, breaker misoperation, or a loose wire. The licensee developed a testing procedure to evaluate the operation of the load sequencing and delay circuits. Electrical Maintenance performed the test with no operational anomalies noted. However, a loose termination was found on the terminal that supplied the

actuation and power input to the load sequencing relay. The licensee determined that this loose termination caused an intermittent connection to the load sequencing time delay relay. The inspector reviewed the applicable drawings with the licensee. The inspector found the licensee's conclusions plausible.

During recovery of offsite power following the test, the Reactor Control Operator (RCO) noted that the 2A EDG kilowatt (KW) chart indicated some governor control anomalies. Concurrently, several licensee personnel reported hearing an abnormal noise from the 2A1 EDG turbocharger. Later, operations restarted the 2A EDG with the System and Component Engineer (SCE) and FP&L Juno Beach diesel specialist present. Both individuals carefully listened to and observed both engines' turbochargers. All noises and equipment behavior were normal for the unit. The governor system operated normally at all loads and speeds. Furthermore, the SCE reviewed the charts of the stability problems. He stated that he had seen similar behavior before, and that it was caused by a known deficiency in the isochronous/droop switch over relay. A modification planned for the next refueling outage was to replace the governor system with an electronic system. The SCE stated that this was the permanent corrective action. The inspector observed a load run of the diesel and reviewed copies of the chart in question. The evaluation was appropriate.

The 2C charging pump started unexpectedly. For the test, the licensee aligned both the 2A and 2C charging pumps to the A electrical bus with both pumps stopped but in AUTO. The B charging pump breaker was racked out. Pressurizer level control was selected to the X channel and the charging pump selector switch was selected to the 2C-2A position. That is, if extra charging flow was required, the 2C pump would start first, then the A pump would start if more flow was required. Per the procedure, the expected response for the test was for A train components to start. The C pump was not expected to start due to an interlock that blocks its starting if the A pump starts during an SIAS. During performance of the test, both pumps started.

The licensee reviewed the sequence of events and determined that both pumps started following the LOOP signal but prior to the SIAS signal. A review of the wiring diagrams showed that only a pressurizer low level signal could have started the pumps at this point. Further diagram review revealed that the pressurizer X channel level control bistable was powered by an A bus Motor Control Center (MCC). When the MCC was deenergized due to the test LOOP, the bistable failed low causing a low pressurizer level signal to be sent to the 2A and 2C charging pumps. Since both pumps were in AUTO, they started. This theory was verified by a zero level spike in the pressurizer level on its recorder. The licensee therefore determined that the 2C charging pump should have started, and the procedure was in error in expecting it not to start. The inspector reviewed the applicable diagrams with Engineering and was satisfied that the licensee's explanation was plausible.

Retest of the A train and testing of the B train was rescheduled to the end of the outage pending completion of the root cause analyses of the A train problems.

c. Conclusions

This performance of Safeguards Testing was challenging to the Operations and Engineering staff. The completed root cause analyses were thorcugh and appropriate for each problem. The reperformance of the test had not occurred at the end of the inspection period.

E8 Miscellaneous Engineering Issues

E8.1 Haul Route Load Test For Unit 1 Replacement Steam Generators (RSG) (50001)

a. Inspection Scope

On May 2, the inspector witnessed the Haul Route Load test performed prior to moving the RSGs on site.

b. Observations and Findings

The haul route was established and the test performed in accordance with Work Package 4501. The purpose of the test was to verify that the SGs could travel along this route without damaging any buried utilities or contacting any structures adjacent to the haul route. The inspector verified that the prerequisites were established prior to commencing the test. The test essentially involved loading the self propelled modular transporter (SPTM) with test weights and then driving the SPTM along the route that it will take when loaded with the RSGs. The test included the route from the boat slip to the temporary storage location. In addition, the route that the old steam generators (OSG) will take was also load tested. The haul route was previously ultrasonically tested with no problem areas identified. This load test was also completed with no problems identified.

c. Conclusions

The test was completed successfully with no problem areas identified.

E8.2 Replacement Steam Generator Work (50001)

On May 4, the Unit 1 RSGs arrived onsite by barge. After the barge was secured the licensee started assembling the ramps from barge to the shore. On May 7, the first RSG was removed from the barge and transported to the temporary storage location inside the protected area. The second RSG was moved to the temporary storage location on May 8. The inspector witnessed both the arrival and transport of the RSGs into the protected area. The licensee transported the RSGs in a very slow and deliberate manner. Quality Control personnel monitored the activity as well as a number of licensee and contract management. The inspector

observed Security personnel as they inspected the RSG and transporter prior to it entering the protected area. No discrepancies were observed during this activity.

IV. Plant Support

S2 Status of Security Facilities and Equipment

S2.1 Status of Security Facilities and Equipment (71750)

a. Inspection Scope

On April 18, 1996, the inspector walked down the protected area barriers. In performing these walkdowns, the inspector verified the fence fabric had no unintentional openings, was not degraded, and was not eroded at the base; isolation zones were free of objects and well illuminated; and compensatory guard postings were in place as necessary.

b. Observations and Findings

The inspector found no discrepancies with the protected area barriers.

c. Conclusions

The protected area barriers were in good condition, the isolation zones well lit, and the appropriate compensatory guard postings in place.

V. Management Meetings and Other Areas

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on May 9, 1997. An interim exit meeting was held on May 2, 1997, to discuss the findings of Region based inspection. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Allen, Training Manager
C. Bible, Site Engineering Manager
W. Bladow, Site Quality Manager
G. Boissy, Materials Manager
H. Buchanan, Health Physics Supervisor
D. Fadden, Services Manager
R. Heroux, Business Manager
H. Johnson, Operations Manager

J. Marchese, Maintenance Manager
C. Marple, Operations Supervisor
J. Scarola, St. Lucie Plant General Manager
A. Stall, St. Lucie Plant Vice President
E. Weinkam, Licensing Manager
W. White, Security Supervisor

Other licensee employees contacted included office, operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 50001:	Steam Generator Replacement
IP 50002	Steam Generators
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 73753	Inservice Inspection
IP 92901:	Followup - Plant Operations
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-335,389/97-01-01	VIO	"Failure to Follow the In-Plant Equipment Clearance Orders Procedure"
50-335,389/97-04-02	VIO	"Routine Use of Heavy Operator Overtime"

Closed

50-335,389/95-17-01	VIO	"Failure to Follow Procedures for Material Controls"
50-335/95-18-02	VIO.	"Failure to Follow Clearance Procedures"
50-389/95-18-03	VIO	"Failure to Adequately Design and Test the Emergency Diesel Generators"
50-389/95-21-03	VIO	"Failure to Perform RCS System Boron Surveillance"
50-335,389/97-03-03	URI	"Excessive Overtime Usage Among Reactor Controls Operators"

Discussed

None

LIST OF ACRONYMS USED

ABB	Asea Brown Boveri
AFW	Auxiliary Feedwater
ALARA	As Low As Reasonably Achievable
ANPS	Assistant Nuclear Plant Supervisor
ASME	American Society of Mechanical Engineers
B&PV	Boiler and Pressure Vessel
CCW	Component Cooling Water
CEA	Control Element Assembly
CFR	Code of Federal Regulations
CIAS	Containment Isolation Actuation Signal
CR	Condition Report
CS	Carbon Steel
CSAS	Containment Spray Actuation Signal
DCN	Design Change Notice
DRS	Division of Reactor Safety
ECO	Equipment Clearance Order
EDG	Emergency Diesel Generator
ERT	Event Response Team
ET	Eddy Current Test
FME	Foreign Material Exclusion
FHB	Fuel Handling Building
GL	Generic Letter
gpm	Gallons Per Minute
HPSI	High Pressure Safety Injection
ICW	Intake Cooling Water
IGSCC	Intergranular Stress Corrosion Cracking
IP	Inspection Procedure
IR	Inspection Report
ISI	Inservice Inspection
IWE, IWL	Subsections of ASME B&PV Code, Section XI
LPSI	Low Pressure Safety Injection
M&TE	Measuring and Test Equipment
MSSV	Main Steam safety Valve
NDE	Nondestructive Examination
NOUE	Notice of Unusual Event
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation, NRC
NWE	Nuclear Watch Engineer
PDR	Public Document Room
PER	Problem Evaluation Report
psig	pounds per square inch (gage)
PWSCC	Primary Water Stress Corrosion Cracking
RAB	Reactor Auxiliary Building
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RL	Refracted Longitudinal UT, e.g., 60° RL
RWT	Refueling Water Tank
S	Shear Wave UT, e.g., 70° S,
SCE	System and Component Engineer

SDC	Shut Down Cooling
SG	Steam Generator
SI	Safety Injection
SIB	Special Inspection Branch
SPDS	Safety Parameter Display System
SNPO	Senior Nuclear Plant Operator
SRO	Senior Reactor Operator
SS	Stainless Steel
TC	Temporary Change
TS	Technical Specification
UGS	Upper Guide Structure
URI	Unresolved Item
UT	Ultrasonic Examination
VIO	Violation
VT-2	ASME Section XI Visual Examination for Leakage