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REGION II

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Licensee: Florida Power & Light Co.

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

Location: 6351 South Ocean Drive
Jensen Beach, FL 34957

Dates: July 27 - September 6, 1997

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EXECUTIVE SUMMARY

St. Lucie Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-335/97-10, 50-389/97-10

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 the results of region based inspections in the areas of engineering and operations.

Operations

- Actions taken by operators to terminate a reactor power increase, experienced while placing a Chemical and Volume Control System ion exchanger in service, were swift and correct. The proper level of attention was afforded this critical evolution. (Section O1.2)

- A leaking condenser tube was identified quickly by Chemistry personnel. Actions taken to minimize the event were timely and in accordance with applicable plant procedures. (Section O1.3)

- An Auxiliary Feedwater System periodic surveillance was performed satisfactorily with no discrepancies noted. (Section O1.4)

- Operator response to a dropped Control Element Assembly during testing was professional. The inspector noted good communications between Operations and Reactor Engineering. The management decision to delay the test until Xenon conditions were stabilized was both appropriate and conservative. (Section O1.5)

- A routine walkdown of the control room ventilation system revealed only minor deficiencies. The inspector found the response and corrective actions for a refrigerant leak adequate. (Section O2.1)

- Although the procedure upgrade program was found to be on schedule, the volume of procedures remaining will present a challenge to the licensee. The prioritization of procedure revisions was appropriate. (Section O3.1)

- A non-cited violation was identified for failure to revise a Quality Instruction after the Nuclear Watch Engineer position was determined to be optional. (Section O3.1)

- Overall, site procedures were found to be adequate to perform their intended functions, availability of current revisions was good, and the procedures were usable, particularly the upgraded versions. As an example, although the licensee had issued only a small percentage of upgraded Annunciator Response Procedures, the inspector noted that they were a significant improvement over the older versions. (Section O3.1)

- The inspector noted that an operator aligning the Gas Decay Tank system was careful and methodical in performing the evolution. Although the operator misread one step, overall procedural adherence was good. (Section O4.1)

Maintenance

- The 1B ion exchanger resin was discharged according to procedure with no major problems noted by the inspector. Good coordination was noted between the groups involved in the activity. (Section M1.1)

- The experience and knowledge of the technicians calibrating 2A High Pressure Safety Injection discharge pressure instrument resulted in timely repair of a unique problem. (Section M1.2)

- The simultaneous performance of maintenance and surveillance was considered a strength in reducing unnecessary starts and periods of inoperability of the 2B diesel generator. (Section M1.3)

- The 2A charging pump accumulators were charged properly in accordance with site procedures. (Section M1.4)

- The inspector noted the technicians were knowledgeable about both the equipment and the procedures being used during Reactor Protection System surveillances. (Section M1.6)

- Although plant cleanliness was generally acceptable, more attention was warranted. (Section M2.1)

- A Quality Assurance audit on Gai-tronics system problems was well performed. The conclusions were well founded and the recommendations were appropriate. The inspector concluded that the licensee's response to QA audit findings was proper, and the programs in place should maintain the Gai-tronic system acceptably. (Section M7.1)

- The inspector concluded that the licensee was actively and methodically working to locate and isolate DC grounds associated with a nuisance alarm. (Section M8.1)

Engineering

- Quality Assurance audits and assessments, and the Site Engineering self assessment efforts were effective in providing oversight of Engineering activities and identifying areas for improvement and increased management attention. (Section E7.1)

- The findings identified by the licensee during the UFSAR/Procedure Consistency Review were documented, processed, and being tracked in accordance with the licensee's corrective action program and NRC regulations. (Section E8.1)

- The inspector concluded that, for the condition reports reviewed, Site Engineering generally provided acceptable responses to address the concerns identified in the applicable condition reports. (Section E8.2)

- A violation was identified for failure to update the UFSAR with the latest information developed to describe the design basis. Enforcement discretion was granted for three examples of UFSAR descrepancies that would more than likely have been identified by the license's UFSAR review program. An NCV was identified for these examples. (Section E8.3)

- The inspector's review of issues surrounding the containment radiation monitors identified potential deficiencies associated with the design basis, as defined by calculation, operability of the system, UFSAR inaccuracies, and timeliness of completing design basis calculations. An Unresolved Item was opened pending further review of these issues. (Section E8.3)

Plant Support

- Although several DC emergency lights were noted to need replacement, work had been planned and replacement batteries were on order. The Preventative Maintenance program for the DC emergency lighting system was found to be adequate to detect any problems with the lights within approximately one month of failure. (Section F2.1)

- With two exceptions, the inspector found the fire suppression system properly aligned and maintained. A pump discharge pipe support was found not supporting the pipe and a recently repaired check valve was left uncoated and exposed to the environment. Other minor deficiencies were noted and corrected or planned to be corrected. (Section F2.2)

Report Details

Summary of Plant Status

Unit 1 entered the period at approximately 90 percent power following recovery from a condenser tube leak. On July 27, the unit experienced a reactivity transient during power ascension due to inadequate flushing of a Chemical and Volume Control System Ion Exchanger. The next day, power was reduced to about 90 percent due to a dropped Control Element Assembly (CEA). The unit was returned to full power early on July 29. The unit experienced one other dropped CEA on August 21. Power was reduced to 88 percent for a short time to allow for recovery. The unit remained at full power for the remainder of the period.

Unit 2 remained essentially at full power for the entire 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 Unit 1 Reactivity Increase When Placing Ion Exchanger In Service (71707)

a. Inspection Scope

On July 27, reactor power increased 2 percent and Reactor Coolant System (RCS) cold leg temperature increased 2.5 °F after the 1A Chemical Volume and Control System (CVCS) Ion Exchanger (IX), was placed in service. The inspectors reviewed Condition Report (CR) 97-1492 which documented the event; as well as the procedures used during the evolution.

b. Observations and Findings

On July 25, the resin in the 1A IX was replaced. On July 25 and 26, steps were taken to equalize the boron concentration of the IX with the RCS, a process known as "rinsing in." This was accomplished by simply routing RCS fluid through the IX allowing the boron to be deposited in the resin. Because the boron concentration of the RCS fluid leaving the IX was reduced, the effluent was routed to a holding tank rather than returned to the RCS. This cycle is repeated until the IX effluent boron concentration is within 25 parts per million (ppm) of RCS concentration. On July 26, approximately 1700 gallons of RCS fluid was diverted through the IX, and a chemistry sample taken at 2:00 p.m. indicated a final boron concentration of 655 ppm. At 3:32 a.m., on July 27, the rinsing in process was again begun. The initial boron concentration sample indicated 233 ppm, which was thought to be in error, based on the previous sample results. A second sample was drawn which indicated the concentration was 633 ppm. At 5:02 a.m., another rinse of the IX was performed with the resulting boron concentration indicating 721 ppm. RCS boron concentration at that time was 717 ppm so the decision was made to place the IX in service. This was completed by 5:45 a.m.. Because small uncertainties in the boron sample analysis can result in small reactivity changes, Operators anticipated having to make corrections as necessary. Additionally, the reactivity change, if one occurred, would not occur immediately because the IX effluent is directed first to the Volume Control Tank (VCT) prior to being pumped to the reactor. At 6:11 a.m., the board operator added 10 gallons of boric acid and 20 gallons of water to the suction of the charging pumps to counteract a slowly increasing RCS temperature. At 6:25 a.m., the IX was bypassed when the RCS temperature continued to rise. RCS temperature increased 2.5 °F from 546 to 548.5 °F. Reactor power increased 2 percent from 87 percent to 89 percent. Operations then added additional boric acid to reduce RCS temperature to the pre-event values.

The licensee immediately initiated an Event Response Team (ERT) to determine the root cause and provide corrective actions. The team concluded the root cause was that the samples were actually taken when the IX was bypassed. This resulted in sampling reactor coolant rather than IX effluent. This occurred because the operating procedure controlling the evolution, OP 1-0210020, Revision 43, "Charging and Letdown - Normal Operation," did not provide enough detail to adequately coordinate the operation of the system and the drawing of the sample. As corrective action, the licensee generated temporary changes (TC) to both units operating procedures to add additional steps to better coordinate the activity. These changes were documented in TC 1-97-071 for Procedure OP 1-0210020 and 2-97-136 for 2-0210020. The licensee followed up the TCs with a permanent change to the same procedures.

The inspector reviewed the event and discussed the details with the involved personnel and considered the licensee's root cause to be accurate. The procedure revisions were reviewed and were determined to provide enough detail to adequately control this evolution.

c. <u>Conclusions</u>

The inspector concluded that the actions taken by the operators to terminate this event were swift and correct. The proper level of attention was being placed on the evolution during this critical time. The revision made to the appropriate operating procedures should prevent this event from occurring again.

O1.3 <u>Unit 1 Downpower Due to Condenser Tube Leak (71707)</u>

a. <u>Inspection Scope</u>

On July 26, Unit 1 experienced a condenser tube leak which resulted in a manual power decrease to approximately 75 percent. The inspector reviewed CR 97-1490 which was written to document the event and determine corrective actions. In addition, the inspector discussed the

event with various Operations and Chemistry personnel. The inspector also reviewed Off-Normal Operating Procedure ONOP-1-0610030, Revision 13, "Secondary Chemistry-Offnormal."

b. Observations and Findings

On July 26, at approximately 6:45 a.m., Chemistry personnel notified the Nuclear Plant Supervisor (NPS) that Steam Generator (SG) cation conductivity was 0.4 umho/cm on both SGs and increasing. Procedure ONOP 1-0610030 was entered and SG blowdown was increased. The ONOP indicated that the plant was initially in an Action Level 1 condition which allowed one week to reach normal chemistry values. Shortly thereafter, Chemistry reported that the analysis indicated the conductivity increase was due to sea water intrusion. Operations commenced reducing reactor power at 7:37 a.m. to remove the suspect 1B1 waterbox from service. However, at 8:05 a.m., Action Level 2 was reached when conductivity exceeded 2 umhos/cm, and a power reduction to less than 30 percent within four hours was commenced in accordance with the ONOP. At 8:10 a.m., the 1B1 Circulating Water pump was secured which terminated the sea water inleakage. By 8:30 a.m., waterbox conductivities were decreasing and SG conductivities had stabilized. By 9:00 a.m., the SG conductivities began to decrease. A clearance was hung on the waterbox for maintenance to commence work. The power decrease was halted at 75 percent.

Maintenance personnel searched for the tube leak using helium and a helium detector but were not successful. However, four plugs were noted to be missing when comparisons were made with the waterbox tube plugging map. The missing plugs were replaced and the plant was brought back to 100 percent power. Secondary plant conductivities remained within normal range.

c. Conclusions

The leaking condenser tube was identified quickly by Chemistry personnel. Actions taken were timely and in accordance with applicable plant procedures.

O1.4 Unit 2 Auxiliary Feedwater (AFW) Periodic Test (61726)

a. Inspection Scope

The inspector witnessed the performance of Procedure OP 2-0700050, Revision 48, "Auxiliary Feedwater Periodic Test."

b. Observations and Findings

The inspector attended the pre-job brief and observed portions of the surveillance in both the main control room and locally at the pump. The procedure was verified to be of the current revision, the Measuring and Test Equipment (M&TE) was within its calibration due dates, and the operators were qualified to perform the task. No discrepancies were identified during the performance of this activity.

c. Conclusions

The surveillance was performed satisfactorily with no discrepancies noted.

01.5 Dropped Control Element Assembly (93702)

a. Inspection Scope

On August 21, the inspector responded to the Unit 1 control room in response to a dropped CEA during Full Length CEA testing. The inspector observed the rod recovery and subsequent power ascension.

b. Observations and Findings

At 8:45 a.m., on August 21, Unit 1 experienced a dropped CEA (A-47) during Full Length CEA Testing per Procedure OP 1-0110050, Revision 35, "Control Element Assembly Periodic Exercise." The operators responded immediately in accordance with Off-Normal Operating Procedure ONOP 1-0110030, Revision 38, "CEA Off-Normal Operation and Realignment." The operators reduced power to approximately 88 percent. This dropped rod was different from most since it was a dual rod shutdown CEA positioned near the "D" linear power range nuclear instrument (NI). This caused a large rod shadow on that NI, and a large axial flux shape variation. In fact, the large power shift caused the operators some minor problems maintaining the opposite side T_H in the normal band.

I&C personnel quickly determined that a power switch had failed, allowing the CEA to drop. By 9:05 a.m., I&C had repaired the problem and Operations had verified CEA operability. Operators had fully withdrawn the rod by 9:25 a.m. The Operations staff acted professionally throughout the event. The NPS and Assistant Nuclear Plant Supervisor (ANPS) minimized extraneous control room activity during the recovery. The inspector noted good communications between Operation and Reactor Engineering (RE). RE support was appropriate and timely. The inspector noted that the recovery to full power was deliberate to allow core power to equalize. The conservative management decision to delay the Full Length CEA test for twenty-four hours was appropriate.

c. Conclusions

Operator response to a dropped CEA during testing was professional. The inspector noted good communications between Operations and RE. The management decision to delay the test a day after CEA recovery was both appropriate and conservative.

02 Operational Status of Facilities and Equipment

02.1 Walkdown of Control Room Ventilation (71707)

a. Inspection Scope

The inspector performed a routine walkdown of both units' control room air conditioning systems. In addition, the inspector followed up on maintenance associated with a refrigerant leak that occurred on the Unit 2 3A air conditioning unit.

b. Observations and Findings

The inspector used Drawings 2998-G-879 SH 2, Revision 16 and 8770-G-852, Revision 22 to perform a system walkdown of the air conditioning systems. Also, Procedures 1-1900020, Revision 12, "Reactor Auxiliary and Control Room Ventilation Operation," and 2-1900020, Revision 10, "Reactor Auxiliary and Control Room Ventilation Operation," were reviewed by the inspector to verify system line up. The inspector found only minor drawing discrepancies that had already been identified to the system engineer.

In May, Maintenance noticed that the Unit 2 air conditioning unit 2HVA/ACC-3A had a pinhole leak at the shell side threaded inlet fitting of the water cooled condenser. A Condition Report (CR 97-1044) was written identifying that 27 pounds of refrigerant had been added and identifying the apparent location of the leak. By the middle of June, Engineering dispositioned the CR by identifying the repair. At that point, the work was placed on the Plan of the Day (POD) to be worked in July. The licensee started a surveillance run of the Unit 2 3A air conditioner on the evening of July 4. Within a few hours, the ANPS determined that the unit was not cooling properly, declared the unit inoperable, and generated a high priority work request to repair the unit. The repairs were completed July 5 with 60 pounds of refrigerant added.

On July 22, Maintenance evacuated the Unit 2 3A air conditioner to repair the leak. They verified the system pressure gages and the pumping unit pressure gages showed that no more refrigerant was present. They then unbolted a solenoid valve bonnet and refrigerant gas escaped into the ventilation room. All personnel were evacuated from the ventilation room, located directly behind the control room. The doors from the control room were opened to vent the control room and vent room areas. The causes of the event were determined to be the following:

1. A lack of procedural guidance. The licensee considered evacuating refrigerant within the skill of the craft and no detailed procedure existed.

2. Inadequate Maintenance training. The crew that performed this work activity had been recently certified to service air conditioning units. The training was inadequate as it did not

include site specific information about the air conditioning units.

3. Inadequate information in the work package. The work package did not include the schematic drawing of the equipment layout that would have shown the craft that a check valve between the condenser heat exchanger and the closed solenoid valve was installed which prevented the reclamation of refrigerant in the lines.

Short term corrective actions included adding guidance to the generic air conditioning work order to ensure evacuation of all piping. Long term corrective actions included development of a procedure to control all air conditioning maintenance. Maintenance also completed repair of the leak and restored the unit to operation.

c. Conclusions

The inspector found only minor deficiencies in the control room ventilation system. The system engineer was already aware of these problems. The inspector found the response and corrective actions to the refrigerant leak adequate.

03 Operations Procedures and Documentation

03.1 Procedure Review (42700)

a. Inspection Scope

The inspector reviewed the licensee's procedures for developing, implementing, and revising plant procedures. Also, the inspector evaluated the licensee's procedure upgrade program, procedure change backlog, and library maintenance. Finally, the inspector surveyed a sample of Administrative, Operations, Maintenance, Chemistry, and Health Physics procedures for usability, accuracy, and conformance with the site Writer's Guide.

b. Observations and Findings

The inspector reviewed the following:

- Both units' Technical Specification (TS) Sections 6.5 and 6.8
- The Topical Quality Assurance Report (TQAR) Section 5.0, Revision 12, "Instructions, Procedures, and Drawings"
- Quality Instruction QI 5-PSL-1, Revision 2, "Preparation, Revision, Review/Approval of Procedures"
- Quality Instruction QI 5-PR/PSL-3, Revision 14, "Verification Guide for Emergency Operating Procedures"
- Quality Instruction QI 6-PR/PSL-1, Revision 32, "Document Control"
- Procedure ADM 11.02, Revision 0, "St. Lucie Procedure Writer's Guide"
- Procedure ADM 11.03, Revision 1, "Temporary Change to Procedures"

The inspector also conducted interviews with several procedure writers, their management, and procedure users to determine the overall effectiveness of the St. Lucie procedure program.

Several years ago the licensee identified that its procedures being used in the field were less than adequate. Sufficient detail was lacking to ensure that minimally qualified personnel could perform a task in a repeatable and acceptable way. About two years ago the licensee began a procedure upgrade program designed to improve and standardize all plant procedures by the year 2000. At the end of this report period, the inspector estimated that approximately 15 percent of the upgraded procedures had been issued with another five percent nearing completion. The licensee had not yet identified what the final population of procedures would be. One Procedure Writer noted that some procedures would be combined while others would be subdivided into separate procedures. Therefore, a final count would be difficult to ascertain. Based upon the information provided by the Procedures Group supervision, the inspector estimated that about thirty-six hundred procedures still required a significant amount of work prior to being issued. This number included 2350 Annunciator Response Procedures (ARPs). The licensee acknowledged that their resources were less than adequate. The large number of procedures to upgrade by the end of 1999 combined with the "normal" duties of revising and reissuing procedures, posed a large challenge to the Procedures Group with its limited resources.

The St. Lucie site maintained two main libraries, one in the South Service Building (SSB) and the other in the North Service Building. The Technical Support Center (TSC), and both libraries all have a complete set of controlled procedures. Several satellite areas also have controlled copies. For example, the diesel generator rooms have portions of controlled Off-Normal Operating Procedures (ONOPs), the hot shutdown panel rooms have controlled copies of the ONOPs and Emergency Operating Procedures (EOPs), and the maintenance area of the D-13 building had some controlled procedures. Each library location contained "For Information Only" procedure title lists. However, according to Quality Instruction QI 6-PR/PSL-1, Revision 32, "Document Control," Section 4.5, the user was to verify controlled copies by using the on-line Passport D150 panel. The inspector verified that the diesel room procedures and the hot shutdown panel room procedures were the current revision and ensured that a sample of the D-13 procedures was current. The inspector noted no discrepancies. The inspector randomly verified twelve operations and administrative procedures in both control rooms. No deficiencies were noted. The inspector randomly selected 52 procedures from all disciplines and verified that they were current in the two main libraries. The inspector found one deficiency that the licensee concurrently identified. Maintenance Procedure MP-0940061, Revision 22, "Maintenance of Thermal Overload Devices," still existed in the SSB files although EMP-100.01, Revision 0, "Maintenance of Thermal Overload Devices," had superseded it in March. The licensee identified the problem in Condition Report 97-1651.

The inspector reviewed fifteen procedures from various disciplines: Operations, Administrative, Maintenance, Health Physics (HP), and Chemistry. These included both upgraded and non-upgraded procedures. Overall, the inspector noted that the upgraded procedures were more uniform in appearance than the non-upgraded versions. However the HP and Chemistry upgraded procedures routinely departed from the Writer's Güide recommendations. All non-upgraded procedures reviewed had been revised within the past year for either clarity, technical content or both. The inspector compared the procedural steps to the plant configuration, where applicable, and determined that the procedures would accomplish their intended function and were usable. The inspector concluded that the format of the upgraded procedures was improved but technical content was comparable to the non-upgraded procedures. However, the consistent use of nomenclature and format did make the procedures more usable.

During the review, the inspectors observed one discrepancy. On August 5, the inspector found that procedure QI 1-PR/PSL-2, Revision 32, "Operations Organization," still described the Nuclear Watch Engineer (NWE) as required for minimum crew manning. Since mid-June, the licensee had allowed the NWE position to remain unmanned as a temporary response to Violation 50-335,389/97-04-02, "Routine Use of Heavy Operator Overtime." The licensee identified the needed revision on June 19 and started the procedure change process. Because Procedure ADM 11.03, Revision 1, "Temporary Change to Procedures," did not permit QI's to be processed as temporary changes, the licensee was forced to perform a normal procedure revision. The revised procedure was approved by the Facility Review Group and signed by the Plant General Manager on July 14. On August 5, Document Control issued the procedure, putting it into effect. The Operations Assistant Supervisor stated that he did not place a higher priority on the change because he did not believe that it was warranted. His primary focus was to get the procedures that were used regularly changed. He understood that the operations staff rarely read QI 1-PR/PSL-2 and did not affect the routine of the Operations Department.

Section 4.2 of Procedure QI 1-PR/PSL-2, Revision 32, stated, "The Operations group consists of five (5) or more shifts with a Nuclear Plant Supervisor in charge of each shift. Each shift consists of the required operators discussed in Section 5.2 of this procedure." Section 5.2.5 stated that a Nuclear Watch Engineer was a required position to be manned. The licensee routinely left the NWE position unmanned since June 9. For both units, Technical Specification 6.8.1.a required that procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, including minimum shift staffing, be maintained and followed. This failure constitutes a failure of minor significance, and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Manual, NCV 50-335,389/97-10-01, "Failure to Update a Procedure."

The inspector also noted that the licensee issued the first set of ARPs in the Unit 1 control room. Each annunciator panel still had a response

procedure book associated with it. Each book now contained a specific, one-page response procedure for each annunciator window. This was a significant improvement over the old ARPs. Operators stated that the new procedures were more useable and accurate than the old procedures. They liked the ability to revise a single annunciator response without revising the entire book. A brief audit of the Controlled Wiring Diagram (CWD) references by the inspector revealed a significant improvement in their accuracy. Of the ten ARPs reviewed, the inspector found no deficiencies in the references. The licensee scheduled the ARP upgrade for completion by December 1998.

The inspector reviewed the procedure revision process. The licensee could change their procedures in two ways. The simplest method was a temporary change. As described in Procedure ADM 11.03, Revision 1, "Temporary Changes to Procedures," personnel should generate a TC when they could not perform a procedure as written and time constraints would not allow revision via the normal procedure change process. The procedure change could not change the intent of the original procedure, require a Facility Review Group (FRG) review, or was not a Quality Instruction, Emergency Plan Implementing Procedure, or an Emergency Operating Procedure. Furthermore the procedure required the following:

- A qualified reviewer perform a 10 CFR 50.59 screening on the TC
- A member of plant management staff review the procedure change to determine if a cross-disciplinary review was required
- A member of plant management staff verification that no change of intent was involved
- A member of plant management staff verification of technical adequacy
- Another member of plant management staff to review the forms and determine the need for a FRG

Technical Specification 6.8 also required the review by two members of plant management and by the FRG within fourteen days. The inspector reviewed fifteen recent TCs. No discrepancies were noted.

The licensee performed normal procedure changes according to procedure QI-5-PSL-1, Revision 2, "Preparation, Revision, Review/Approval of Procedures." This procedure required those appropriate subcommittee reviews, 10 CFR 50.59 screenings, UFSAR reviews, and FRG reviews be performed. The inspector reviewed nineteen recently approved procedures from Operations, Maintenance, Administrative, Emergency Operating Procedures, and Emergency Plan Implementing Procedures. The inspector reviewed them for agreement with licensing documents and for administrative compliance. The inspector found no deviations.

The licensee actively tracked the procedure backlogs, the number of procedure changes due to technical inaccuracies, and the number of active TCs as indicators of their performance. The inspector noted a positive trend in all areas for the last few months. At the beginning of July, the procedure backlog was approximately 76 items. They were equally distributed among word processing, proofreading, and

administrative holds such as training. At the beginning of August the backlog was down to 42 items. This time, however, about half the backlog was for an administrative hold. Technical inaccuracies were down during 1997 over a comparable period last year. Most notably, the licensee reduced the inaccuracy rate for the improved procedures to about 2 percent of the issued improved procedures. This was down from approximately 6 percent the year before. The non-improved procedures also had an inaccuracy rate of about 2 percent for 1997.

c. Conclusions

The procedure upgrade program at St. Lucie was scheduled to continue into December 1999. The prioritization of upgrading was generally appropriate. However, the licensee may not have allocated sufficient resources to attain the completion date as evidenced by the large percentage of the project remaining combined with the burden of normal, non-upgrade revision of the remaining procedures. Overall, the inspector determined that the procedures were adequate to perform their intended function, availability of current revisions was good, and the procedures were usable, particularly the upgraded versions. Although the licensee had issued only a small percentage of upgraded ARPs, the inspector noted that they were a significant improvement over the older versions. The inspector determined that control of procedure changes was adequate. The inspector found a positive trend in procedure backlog reduction. One NCV was identified for failure to properly revise a procedure to update the Operations staffing requirements following a change to those requirements.

O4 Operator Knowledge and Performance

O4.1 Operations Swapping Gas Decay Tanks (71707)

a. Inspection Scope

The inspector witnessed an operator remove the 1B Gas Decay tank (GDT) from service and place the 1A GDT in service. In addition, the waste gas analyzer was aligned for service.

b. Observations and Findings

On July 30, the inspector witnessed an operator remove the 1B GDT from service and place the 1A GDT in service. The operator had and followed the appropriate procedure. The inspector noted that when the operator had questions about the evolution, control room operators were contacted for resolution. While performing the valve lineup for placing the waste gas analyzer in service, the inspector noted that the operator verified a valve closed rather than open as required by procedure. When questioned by the inspector the operator reviewed the procedure, noted the error, and opened the valve. Additionally, the inspector noted several tools inside the panel housing the waste gas analyzer. It appeared as though they were left by maintenance personnel. The

appropriate licensee representative was notified and the tools were removed.

c. Conclusions

The inspector noted that the operator was careful and methodical in performing this evolution. Although the operator misread one step, overall procedural adherence was good.

04.2 Full Length Control Element Assembly Test (61726,71707)

On August 22, the licensee performed a Full Length Control Element Assembly test on Unit 1 per Procedure OP 1-0110050, Revision 35, "Control Element Assembly Periodic Exercise." This test had been originally started the previous day but was delayed after dropping a CEA. The inspector noted that the actual testing was being performed by an operator-in-training and supervised by a qualified operator. An extra operator was assigned to the shift to allow the operators performing the test to concentrate on the test. The operators performed the test according to the procedure and kept the ANPS informed of the status at all times. Operator attention to the test was good. The pre-job briefing was adequate for the task.

08 Miscellaneous Operations Issues

08.1 (Closed) LER 50-389/96-001-00, "Manual Reactor Trip Due to High Main Generator Cold Gas Temperature" (92901)

On January 5, 1996, Unit 2 was manually tripped by utility licensed operators due to an increasing main generator cold gas temperature. The primary cause of this event was the failure of Temperature Control Valve (TCV) TCV-13-15 to automatically regulate cooling water flow from the main generator hydrogen coolers following local closure of the TCV bypass valve. A subsequent inspection showed that the valve controller derivative setting was incorrectly adjusted. Post maintenance testing performed after recent controller maintenance was insufficient to assure proper system operation. A contributing factor was the failure of Operations personnel to adequately monitor the evolution and ensure that system response was as expected following the local actions. Several unexpected SG low level indications were received following the trip and were subsequently found to be caused by partial sensing line blockage from accumulated corrosion products.

Corrective actions for this event included the following:

1) The TCV controllers setting was adjusted prior to returning Unit 2 to service.
2) Additional controllers in other plant systems were inspected for proper operation.
3) Post maintenance testing of controllers was reviewed for adequacy.

4) Operations evaluated generic implications and required additional oversight for this evolution in the future.
5) Controller setpoints were reviewed for inclusion into a data base.
6) Unit 2 SG level instrumentation sensing line blockage was cleared, and instrument performance was reviewed for Unit 1.
7) SG level sensing lines and others deemed susceptible will be blown down in the future as part of a preventative program.
8) Plant procedures were revised to facilitate early detection of instrumentation discrepancies.

The inspector reviewed the licensee's corrective actions and determined that they had been completed satisfactorily. Therefore, this item is closed.

08.2 (Closed) LER 50-335/96-003-00, "Containment Particulate and Gaseous Monitor Out of Service Resulting in a Condition Prohibited by Technical Specifications Due to Personnel Error" (92901)

This subject LER documented a HP technician failing to return a throttle valve to its open position after a containment air sample was obtained on February 22, 1996. The root cause of this event was personnel error attributed to the HP technician for not following procedure. Subsequently, VIO 50-335/96-04-01, "Failure to Follow Procedures Lead to Unit 1 Containment PIG Inoperability," was issued for this event. The details of this incident were previously discussed in Inspection Report 97-06, Paragraph 08.1. The inspector reviewed the licensee's corrective actions for this event and found that they had been satisfactorily implemented. Therefore, this LER is closed.

08.3 (Closed) LER 50-335/96-004-00, "Inadvertent Manual Start of the 1A Emergency Diesel Generator Due to Personnel Error" (92901)

a. Inspection Scope

On February 27, 1996, an inadvertent manual start of the 1A Emergency Diesel Generator (EDG) was initiated when an Instrumentation & Control (I&C) technician, working inside the 1A EDG control cabinet, accidentally bumped the actuating stem on a relay mounted on the inside of the cabinet. The inspector reviewed the event and the subject LER.

b. Observations and Findings

The investigation determined that the root cause of this event was personnel error. The Nuclear Plant Work Order (NPWO) recommended that a clearance be used. A sign was posted on the front of the EDG control cabinet door warning that there was equipment inside the cabinet which could cause an EDG start. The I&C Supervisor did not request a clearance before scheduling work to commence in the EDG control cabinet. The acting control room supervisor authorized work to commence in the 1A EDG control cabinet without a clearance. Corrective actions were inclusion of the EDG control cabinet under requirements of Procedure AP 0010142, "Unit Reliability-Manipulation of Sensitivity Systems,"

personal discussion of the incident and its importance with the responsible parties by the licensee management, and a special training bulletin to all maintenance and operations personnel that reinforced the importance of using clearances to avoid inadvertent actuation of plant equipment.

The inspector reviewed the licensee's corrective actions for this event and found that all corrective actions had been satisfactorily implemented. However, the inspector found that Procedure AP 0010142, "Unit Reliability-Manipulation of Sensitivity Systems," was later deleted and incorporated into Procedure ADM 0010432, "Nuclear Plant Work Orders." Subsequently, the inspector reviewed the following plant procedures and discovered that they still referenced Procedure AP 0010142.

- Operations Policy OPS-502, Revision 0, "Pre-Evolution Briefs"
- AP 0010532, Revision 6, "Relay Work Orders"
- ADM 08.01, Revision 6, "On-Line Leak Sealant Procedure"
- AP 0010460, Revision 10, "Critical Maintenance Management"
- AP 0005758, Revision 7, "Electrical Maintenance New Employee Indoctrination Guidelines"
- ADM 17.07, Revision 3, "Flow Accelerated Corrosion Inspection Implementation Program"

The discrepancies were brought to the licensees' attention and subsequently, a Condition Report 97-1584 was initiated to perform root cause evaluation and to determine any potential generic implications and corrective actions. The failure by the licensee to remove a reference of Procedure AP 0010142 from the affected plant procedures was identified as a weakness in the licensee's procedure upgrade program.

c. Conclusion

The inspector determined that the licensees' corrective actions were appropriate to avoid a repeat event. However, the failure by the licensee to remove a reference of AP 0010142 from the affected plant procedures was identified as a weakness in the licensee's procedure upgrade program.

08.4 (Closed) VIO 50-335,389/96-11-04, "Preconditioning of Valves Prior to Surveillance" (92901)

This violation documented the failure of the licensee to ensure that the procedures (AP 1-0010125A, Revision 39 and AP 2-001025A, Revision 43) were performed under suitable environmental conditions. Specifically, these two procedures allowed four containment spray valves to be lubricated prior to being tested. The details of this incident and the licensee's corrective actions were previously discussed in Inspection Report 96-11, Paragraph E2.1. The inspector reviewed the licensee's corrective actions as specified in the Florida Power & Light (FPL) response to the subject Notice of Violation (NOV), dated September 27, 1996. The inspector verified that all corrective actions were properly implemented. Therefore, this item is closed.

O8.5 (Closed) VIO 50-335,389/96-16-02, "Failure to Control Operation Keys" (92901)

This violation addressed the licensee's failure to properly control the keys used for the electrical isolation of the Power Operated Relief Valves (PORVs) as required by Procedure AP 2-0010123, "Administrative Control of Valves, Locks and Switches." The inspector reviewed the licensee's corrective actions as specified in the FPL response to the subject NOV, dated October 18, 1996. The inspector verified that all corrective actions were properly implemented. Therefore, this item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Chemical and Volume Control System Ion Exchanger Resin Discharge (62707)

a. Inspection Scope

The inspector observed portions of the Chemical and Volume Control System Ion Exchanger Resin Discharge on Unit 1. The inspector reviewed the radiological controls in place and operator procedural conformance and knowledge of the evolution.

b. Observations and Findings

Resin discharge was done in accordance with Procedure OP 1-0520020, Revision 36, "Radioactive Resin Replacement" in conjunction with Health Physics Procedure HP-40, Revision 43, "Shipment of Radioactive Material." The licensee discharged the resin to a shipping container staged outside the Reactor Auxiliary Building (RAB). The container was then sealed and shipped offsite for burial at an approved site.

On July 29, the inspector observed the discharge of the 1B CVCS purification ion exchanger. The inspector noted good coordination between Operations and Health Physics. All personnel appeared to be familiar with the procedures, and communications were generally good. The inspector did notice a short period when communications between the shipping container and inside the RAB were lost. An extra person was dispatched from the container into the RAB to inform them that the radio was not working at that location. The resin discharge and flush were completed without further problems.

c. Conclusions

The 1B ion exchanger resin was discharged according to procedure with no major problems noted by the inspector. Good coordination was noted between the groups involved in the activity.

M1.2 Calibration of the 2A High Pressure Safety Injection Discharge Pressure Indicator (62707)

a. Inspection Scope

The inspector witnessed I&C personnel calibrate the 2A High Pressure Safety Injection (HPSI) discharge pressure indicator in accordance with Work Order (WO) 97010910 and I&C Procedure 2-140064P, Revision 36, "Installed Plant Instrumentation Calibration (Pressure)."

b. Observations and Findings

On July 30, the inspector witnessed I&C perform portions of a transmitter calibration. The inspector verified the proper procedure was being used, the M&TE was calibrated and controlled, and the appropriate prerequisites had been completed. After the transmitter was isolated and the test equipment attached, the technicians noted the pressure indication increasing on the test meter. With the transmitter isolated, the pressure should not have increased. The test equipment was removed, a valve lineup of the transmitter completed and the equipment reattached. The transmitter again indicated an increasing pressure. The technicians manually increased the pressure with an installed pressure source and noted an erratic response from the transmitter. The technicians initially thought the transmitter had failed but noted that neither of them had ever seen one fail in that manner. After several minutes of discussion one of the technicians recalled having seen a similar problem when Neolube was accidently dropped on the circuit board located inside the transmitter. The transmitter was opened and Neolube was found on the board. Neolube is a conductive lubricating material that is applied to the threads of the end caps on the transmitter. Prior to starting the calibration, the technicians had opened the transmitter to perform another part of the procedure. While applying the Neolube, the technician accidently brushed a small amount onto the circuit board. After cleaning the neolube from the board, the transmitter was successfully calibrated.

c. Conclusions

The experience and knowledge of the technicians calibrating this instrument resulted in timely repair of a unique problem.

M1.3 Governor Maintenance and Load Run on 2B Diesel Generator (61726,62707)

a. Inspection Scope

On August 28, the licensee scheduled preventive maintenance on the 2B Emergency Diesel Generator to occur just prior to the monthly load run. The inspector observed the coordination between maintenance and operations and portions of the subsequent load run.

b. Observations and Findings

On July 10, the 2A EDG experienced erratic behavior due to set screws on the mechanical governor vibrating loose. The licensees' repair was to install the set screws with lock-tite. On August 28, the licensee scheduled the 2B EDG for its monthly load run and determined that this would also be an ideal opportunity to perform the maintenance on this diesel's governors. Because the diesel is inoperable for a period when the Senior Nuclear Plant Operator (SNPO) jacked the machine, the licensee planned to perform the maintenance then.

Shortly after the start of peak shift on August 28, the ANPS held a brief with the crew. The briefing consisted of those individuals involved in the evolution and covered the precautions of the operating procedure and contingency actions for possible failures. The ANPS also covered the maintenance activity allowing the System Engineer time to discuss the job and the reason behind it. Overall the inspector judged the brief to be above average.

At 4:45 p.m., the SNPO entered the EDG room to begin work, the electrician was already in the room near the 2B1 EDG governor. They performed the maintenance in accordance with Work Order 97017209 01. The procedure had the electrician remove each of the three set screws one at a time and reinstall with lock-tite. Any problems were to be resolved with the System Engineer who was on station. The work did not begin until the SNPO disabled the diesel for jacking purposes. This was essentially a tagout without paper. The inspector questioned the Quality Assurance (QA) Manager, who was present for the evolution, about the need for a clearance. He brought in the System Engineer to explain why no tags were needed. He explained that this was just an extra precaution, no tags would be needed at all for his safety since he was not near any rotating equipment. Although the Equipment Clearance Procedure is not clear for this case, the inspector was satisfied that the worker's safety was not in jeopardy. The QA Manager initiated a Condition Report (CR 97-1668) to clarify the issue. The maintenance was performed per the work order and in a timely manner. The inspector judged this to be an effective use of the inoperable diesel time.

The licensee started and ran the 2B EDG according to Procedure OP 2-2200050B, Revision 30, "2B Emergency Diesel Generator Periodic Test and General Operating Instructions." The inspector noted that the SNPO appeared very familiar with the machine, and followed the procedure as written. The inspector did not see any anomalies with the load run.

c. Conclusions

The inspector observed maintenance activity on the 2B EDG followed by the monthly load run. The combination of the maintenance and load run was considered a strength in reducing unnecessary starts and periods of inoperability of the diesel.

M1.4 Unit 2 Charging Pump Accumulator Pressure Checks (62707)

a. Inspection Scope

The inspector witnessed the licensee charge the suction and discharge pressure accumulators for the 2A charging pump.

b. Observations and Findings

This maintenance was performed in accordance with WO 97015744 and Procedure MP-2-M-0018, Revision 52, "Charging Pump Accumulators 2A, 2B, and 2C Pressure Check/Recharge." The inspector verified the proper revision of the procedure was used, the M&TE calibration of the instrumentation was current, and the prerequisites had been completed prior to starting work.

The nitrogen supply was from installed piping connected to the plant nitrogen system. To charge the accumulators, the licensee simply connected high pressure hoses and a small pump between the installed piping and the accumulators. The maintenance personnel were very familiar with performing this work and completed the task satisfactorily.

The only discrepancy noted by the inspector was also identified by the licensee and promptly corrected. One of the maintenance workers slightly stepped into the roped off contamination zone. The health physics technician assigned to monitor the work, saw this occur and instructed the worker to step back. A survey was conducted and the area was found to be clean.

c. Conclusions

The 2A charging pump accumulators were charged properly in accordance with site procedures.

M1.5 Diagnostic Testing of 2-V2525, Boron Load Control Valve (62707)

a. Inspection Scope

The inspector witnessed portions of the performance of Maintenance Procedure 0940079, Revision 6, "VOTES 100 System Operating," which was used to perform testing for the 2-V2525.

b. Observations and Findings

This valve was being tested monthly because Engineering had previously identified that the thrust at the torque switch trip was less than required. This information was documented in CR 97-1190 and the testing was being tracked by PMAI 97-06-282. The CR concluded that the problem was a result of inadequate lubrication at the stem/stem nut interface. This area was cleaned and relubricated. The CR required testing was to be performed monthly for six months to monitor the condition.

The inspector reviewed the WO that actually contained the work instructions and noted that all the prerequisites had been completed. The procedure was reviewed and noted to have several missing signatures. Discussion with the personnel performing the activity, revealed that tables at the back of the procedure contained the same signoffs as those in the body of the procedure. The signoffs in the table had been completed. Upon discovery, the duplicate steps in the body of the procedure were signed as well.

The inspector witnessed the valve being stroked and data being taken. After the data was reviewed, the analyst concluded that the valve was operating properly and no additional testing or maintenance was required.

c. Conclusions

The inspector concluded that the personnel observed performing this task were qualified and knowledgeable about diagnostic testing. No discrepancies were identified with this evolution.

M1.6 Unit 2 Reactor Protection System Testing (61726)

a. Inspection Scope

The inspector witnessed portions of the performance of two Reactor Protection System (RPS) surveillances, I&C Procedure 2-1400160, Revision 13, "Channel Calibration delta T power - Quarterly," and 2-1400198, Revision 4, "RPS Channel Calibration Variable High Power Quarterly."

b. Observations and Findings

The inspector observed two technicians perform the Channel A portions of each of these tests. The procedures were noted to have been well written and required little interpretation. The technicians were observed to follow the procedure verbatim. In addition, the inspector noted that the technicians were extremely knowledgeable about the equipment being tested and the procedures being used.

c. Conclusions

The inspector noted the technicians were knowledgeable about both the equipment and the procedures being used during these surveillances. In addition, the procedures were noted to have been well written and easy to follow.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Material Condition of Plant (62707,71707)

a. Inspection Scope

During routine tours and maintenance inspections, the inspectors identified a number of items impacting the overall material condition of the plant.

b. Observations and Findings

During routine plant tours and inspections, the inspectors identified the following items:

- On July 7, tools were found inside of the Unit 1 waste gas analyzer panel

- On August 21, on Unit 1, an unsecured ladder was found wedged between the 1B battery room wall and the 125 volt DC load test panel in the cable spreading room.

- On August 21 and September 5, on Unit 1, an unsecured ladder was found leaning against the 480 volt load center 1A2.

- On August 21, on Unit 2, Door RA84, located on the 19.5 ft elevation of the RAB was found blocked open. A sign attached to the door stated that people exiting were to ensure the door was closed.

- On August 27, fire locker 4, located on the 43 ft elevation of the Unit 1 RAB, contained four flashlights used as emergency lighting by the fire brigade. One of the flashlights contained a dead battery and the other three flashlights were extremely dim.

- On August 27, on Unit 2, fire door 43, located on the 19.5 ft elevation of the RAB, was found blocked open.

- On August 28, on Unit 2, an unsecured ladder was found leaning against the wall in the CVCS hallway, on the 19.5 ft elevation of the RAB.

- On September 3, the access doors to the 1A and 1B LPSI pump rooms were found to have been secured by only one latch. Each door has eight latches.

- On September 3, an unsecured ladder was found erected over the 2B containment spray pump instrumentation.

Each of these conditions were brought to the licensees' attention and were promptly corrected.

In addition, on August 29, scaffold located in the Unit 1 fuel transfer canal was found suspended by carbon steel cables. Procedure QI 13-PR/PSL-2, Revision 31, "Housekeeping and Cleanliness Control Measures," Step 9.D.8, states that materials fabricated from carbon steel shall not be stored in the pool. However, the procedure did not specifically apply the same restriction to the fuel transfer canal. Reactor Engineering and Chemistry were contacted to determine if this was a concern. The Chemistry supervisor stated that carbon steel components were not allowed in the spent fuel pool because the boric acid solution would cause the component to deteriorate. He stated that although, on occasion, the fuel transfer canal and the spent fuel pool communicate with one another, the cable would not be a problem as long as it did not remain there underwater for an extended period of time. The inspector verified that the maintenance activity was performed in a dry atmosphere and therefore would not be a concern with respect to boric acid induced degradation.

c. Conclusions

While plant cleanliness was generally acceptable, more attention was warranted.

M7 Quality Assurance in Maintenance Activities

M7.1 Longstanding Gai-tronics Deficiencies (62707)

a. Inspection Scope

In July, Quality Assurance issued an audit report (QSL-EP-97-05) that documented several Emergency Plan deficiencies. QA's first finding discussed the licensee's ineffectiveness in resolving longstanding audibility problems of the Gai-tronics public address system. The inspector reviewed QA's finding and the licensee's response to correct the problem.

b. Observations and Findings

The Gai-tronics system was the St. Lucie site's primary means of notification to personnel in case of an emergency. Section 4.6 of the Emergency Plan, Revision 32, stated, "The [Public Address] (PA) system, with speakers strategically located throughout the Protected Area, provides for the transmission of warning and instructions in the event of an emergency." The licensee concluded that, "... the Gai-tronics system has not received the necessary priority and attention to maintain acceptable system performance." QA further concluded, "Corrective actions to address Gai-tronics deficiencies have not been successful in resolving long term problems."

In November 1994, the licensee initiated St. Lucie Action Report (STAR) 0-94110315 to assess the PA coverage at the site and to make necessary improvements to the system. The licensee issued Plant Manager's Action Item (PMAI) PM 96-02-423 to close out the STAR and carry out corrective actions. Initially, a due date of April 1, 1996, was assigned but was later changed to September 1, 1996. In November 1996, Inspection Report 50-335,389/96-18 documented a licensee weakness in failing to ensure the implementation of timely corrective actions, specifically failing to correct Gai-tronic audibility deficiencies identified in STAR 0-94110315.

In December 1996, the licensee audited the site wide audibility of the Gai-tronics system, identifying several deficiencies. The licensee issued a Nuclear Plant Work Order, WO 97001256 to address these deficiencies. At the time of the QA audit, some items had been repaired but the work order remained open. QA identified that the system ground readings were low, troubleshooting was difficult, and other maintenance priorities were taking precedence.

The audit went on to discuss several other documented problems with the Gai-tronics system identified by plant personnel. Condition Report 97-0296 identified the lack of speakers in the Management Information System office area. Condition Report 97-0589 discussed a loud hum from the system in the control room. In May, CR 97-0787 identified that PA announcements were not heard in the Unit 2 containment. Finally, Condition Reports 97-0998 and CR 97-1009 identified the lack of working speakers in the North Service Building.

QA concluded that this finding was another example of a weakness previously identified by the licensee with less than effective corrective action implementation and follow through. QA recommended three actions. First, the licensee should commit the necessary time and resources to promptly address the problems. Second, the licensee should start a preventative maintenance program to periodically test and repair the plant page system. Third, the licensee should review the impact of additional page stations prior to installation. The inspector found the audit finding thorough, the conclusions accurate, and the recommendations appropriate.

In June 1997, the licensee formed a task team to address the PA system concerns identified in CR 97-0998 and CR 97-1009. The team's recommendations were not issued until after the QA audit and therefore included input from the audit. NPWO 5306/67 identified which stations were broken. PMAI 97-07-119 was issued to track paging station repairs. All repairs were completed by August 15. The licensee established a surveillance program for the system on August 29. The first test occurred on September 4. The area tested was in the turbine buildings and steam trestles. Although overall the test was satisfactory, several discrepancies were noted. The licensee captured the information in a NPWO and repair work began that afternoon. Last, the licensee issued PMAI 97-07-122 to develop a tracking mechanism for the paging system performance. This was completed on September 5. Senior licensee management was holding those responsible for the completion of the items accountable. No due dates were allowed to be extended without the QA Manager's and Site Vice-President's approval. The inspector concluded that the licensee had committed the resources to properly resolve the problems with the Gai-tronic system.

The inspector randomly verified the operability of Gai-tronic stations in the power block. All units checked were operable. Also the inspector ensured that the plant telephones were working. No problems were noted.

c. Conclusions

The QA audit on the Gai-tronics problems was well performed. The inspector found the conclusions to be well founded and the recommendations to be appropriate. The inspector concluded that the licensee's response was proper, and the programs in place should maintain the Gai-tronic system acceptably.

M8 Miscellaneous Maintenance Issues

M8.1 Licensee Control of Nuisance or Frequently Alarming Annunciators (62707,37551)

a. Inspection Scope

The inspector reviewed the licensees list of annunciators in alarm, the controlling procedure, AP 0010120, Revision 94, "Conduct of Operations," associated work orders, and condition reports, to determine if the licensee was adequately addressing this issue.

b. Observations and Findings

The inspector reviewed the activities associated with three CRs concerning nuisance annunciators. Procedure AP 0010120 defined a frequently alarming annunciator as one which was unexpected and alarmed at least twice in a twenty-four hour period. It stated that action should be initiated to correct the cause of the alarm. This procedure defined a nuisance annunciator as one which was unexpected and alarmed greater than or equal to eight times in any eight hour period. The procedure stated that immediate corrective action was to be taken to correct the cause of nuisance annunciators, up to the point of calling out the necessary personnel to correct the cause.

CR 97-1178 was written to document that when the Unit 2 station air compressor was started, annunciator F-14, "Station Air Compressor Temp Hi/Overld/Trip," would alarm. WO 97008404 was written to troubleshoot and repair. Maintenance determined the problem to be associated with the overload trip/alarm contacts on the 480 V breaker. A scope change was made to the WO which allowed the alarm setpoint to be increased. However, the setpoint was still within the acceptable limits previously established in the procedure. The work was successfully completed in

accordance with Procedure MP 0920070, Revision 10, "Periodic Maintenance of 480 Volt ITE Circuit Breakers," Section 4.0.

CR 97-1417 was written to document that Unit 1 annunciator N-25 was a frequent alarm. This alarm was caused by the reactor drain tank (RDT) pressure transmitter intermittently failing low. Maintenance performed initial troubleshooting in accordance with WO 97013779, which determined the problem to be a failing transmitter. Because the transmitter is located in a high radiation area it was scheduled for replacement during the upcoming refueling outage.

The third issue involved annunciator A-10, "125 Volt DC Bus 1B Ground," which was continuously alarming and was identified as a nuisance alarm on June 8, 1997. CRs 97-1265 and 97-0496 were written to document this recurring problem.

Initially Maintenance located grounds in the fire detection system heat detectors for the turbine lube oil and hydrogen seal oil systems. WO 97007805 was written to locate the faulty detectors and replace as necessary. This activity was completed on the turbine lube oil system and the hydrogen seal oil system has been scheduled for repair.

In addition, a ground was found on a wire associated with the start circuit for the 1A2 reactor coolant pump. This ground was isolated by lifting the affected wire. This activity was documented in temporary system alteration (TSA) 1-97-012.

Additional grounds still existed on the system that have not yet been located. Engineering concluded that the grounds being detected were small and not of major concern. As a result, TSA 1-97-017 was developed which disabled the annunciator and installed a voltage meter in the main control room. Operations personnel monitored the meter hourly and if a ground of a predetermined magnitude was detected, the annunciator response procedure was implemented. In addition, the sensitivity for the ground alarm relays associated with the 1B and 1BB battery chargers was reduced in accordance with engineering evaluation JPN-PSL-SEEJ-90-029 and plant specific guidance. At the end of this report period, Engineering was reviewing the ground detection system to determine if it needed to be modified to make it more effective.

Because grounds still existed on the system, various circuits supplied by the 1B bus, were routinely monitored in an attempt to isolate and locate the remaining grounds.

The inspector reviewed the WOs and TSAs associated with the aforementioned problems. Discussions were held with numerous operators, engineers, and maintenance personnel regarding this problem. In addition, the inspector reviewed the applicable procedures concerning TSAs and nuisance annunciators. No discrepancies were identified.

In addition, CR 97-1265 indicated that corrective action to repair/disable annunciator A-10 was not taken, in that personnel necessary to correct the problem were not called to the plant because the event occurred on a weekend. The inspector discussed this CR with Operations, Maintenance, and Engineering management and concluded that the actions taken were prudent. The licensee stated that the personnel knowledgeable on the system were unavailable to respond and searching for electrical grounds was too risky to be performed without adequate planning and the proper staff. However, sufficient staff was available to determine that the grounds causing the alarm were not sufficiently large to warrant immediate attention.

The inspector questioned the licensee about why the annunciator was not disabled to prevent the operators from being unnecessarily challenged and burdened by it being in a constant state of alarm. The licensee stated that a process did not exist which would allow annunciators to be disabled without first being subjected to a lengthy review process. At that time, annunciators were being disabled by the use of Procedure AP 0010124, Revision 43, "Temporary System Alteration Control." However, this process required a large amount of review/work by the system engineer. Because this person was unavailable when the annunciator was in constant alarm, disabling the annunciator was not considered an immediate option. At the end of the report period, the licensee was in the process of developing a procedure which would allow the on shift operators to disable annunciators, upon successful completion of a screening process. This would result in a more timely response to nuisance annunciators.

c. Conclusions

The inspector concluded that frequent and nuisance annunciators place an unnecessary burden on the board operators. The ability to rapidly resolve annunciator problems is crucial to ensure that a valid annunciator is not masked by one which is in a constant state of alarm. In the examples discussed above, the inspector concluded that the licensee was actively and methodically working to locate and isolate grounds associated with this DC bus. The effectiveness of rapidly resolving nuisance annunciators will be enhanced with the implementation of the proposed procedure for disabling nuisance annunciators.

III. Engineering

E7 Quality Assurance in Engineering Activities

E7.1 Quality Assurance Audits and Assessments (40500)

a. Inspection Scope

The inspector reviewed selected daily quality reports, audit reports, and technical review activity reports. These various reports documented oversight activities of the Site Quality Assurance Department. The inspector also reviewed selected self assessment activities performed by Site Engineering. The inspector reviewed the audits and assessments to

determine if findings were documented and processed in accordance with the licensee's corrective action program and NRC regulations.

b. Observations and Findings

The inspectors noted that Site QA had observed various activities which involved Site Engineering. These observations were documented in QA Quality Reports. Site QA had issued over 20 Quality Reports since January 1997. The inspector noted that nearly 50 percent of the QA Quality Reports found unsatisfactory results for activities related to Site Engineering. Site QA issued condition reports to document the unsatisfactory results. Site Engineering had initiated actions to address the QA observations.

The inspector reviewed QA Audit Report QSL-EFF-97-01. During this review, the inspector noted that one of the audit findings identified configuration control concerns regarding quality related equipment (fire protection equipment as an example) that were not clearly identified as quality related in the Total Equipment Data Base (TEDB). Condition Report 97-0592 documented other quality related equipment that was not properly identified in the TEDB. Site Engineering initiated corrections to address this QA finding.

The inspector also reviewed QA Audit Report 08.03.MKFOHV.97.1*. This audit was a limited scope audit performed on the Steam Generating Team Ltd. (SGT) design control process. SGT is a Morrison Knudsen Corporation and Duke Engineering & Services, Inc., company which the licensee had contracted with for the engineering and replacement of the Unit 1 steam generators. This audit was performed by the quality assurance staff put in place by the licensee to provide oversight of the Steam Generator Replacement Project (SGRP) activities. The inspector noted that the audit team identified four findings. The audit findings were being addressed by SGT management.

The inspector also reviewed selected QA Technical Review Activity Reports. These monthly reports provided a summary of oversight activities completed by the Technical Review and Assessments (TRA) group within Site QA. The inspector noted that the TRA group was responsible for performing the independent technical review function that had been performed previously by the Independent Safety Engineering Group (ISEG). The ISEG function was transferred to the QA organization as a result of a licensee Technical Specification amendment request that was approved by the NRC on December 22, 1994. The inspector reviewed TRA monthly reports for the period January 1997, through July 1997, and focused on the engineering activities reviewed by the TRA group. The inspector noted that the TRA group identified a number of findings and initiated several CRs as a result of the activities observed. The inspector noted that Site Engineering was taking actions to address the findings identified by the TRA group.

In addition to reviewing the QA audit and assessment efforts, the inspector also reviewed the results of the Site Engineering self assessment for the second quarter of 1997. This self assessment covered the performance of Site Engineering for the months of March, April, and May, and was centered around the St. Lucie Unit 2 Cycle 10 refueling outage activities. The inspector noted that the self assessment of Site Engineering found areas of strength, areas that were acceptable, and areas for improvement. Site Engineering had initiated actions to address the areas for improvement.

c. Conclusion

The inspector concluded that the QA audits and assessments, and the Site Engineering self assessment efforts were effective in providing oversight of Engineering activities and identifying areas for improvement and increased management attention. The inspector verified that findings identified by the licensee during the audits and assessments were documented and processed in accordance with the licensee's corrective action program requirements and NRC regulations.

E8 Miscellaneous Engineering Issues

E8.1 Updated Final Safety Analysis Report Review Program (37550,40500)

a. Inspection Scope

The inspector reviewed the results of the licensee's Updated Final Safety Analysis Report (UFSAR)/Procedure Consistency Review effort to determine if the findings identified by the licensee were documented and processed in accordance with the licensee's corrective action program and NRC regulations. The inspector also reviewed the status of the licensee's efforts to conduct a graded review of the St. Lucie Unit 1 and Unit 2 UFSARs.

b. Observations and Findings

UFSAR/Procedure Consistency Review

The licensee, initiated this UFSAR review as part of the corrective actions for a violation issued by the NRC for the St. Lucie Unit 1 Boron Dilution Event of January 22, 1996. In a letter dated April 23, 1996, FPL committed to review the Unit 1 and Unit 2 UFSARs and plant procedures for mutual consistency. This review was to be completed by December 31, 1996.

The Site Engineering Department was assigned the lead to perform the review of the UFSARs and procedures. The licensee formed a UFSAR project team in August 1996, which consisted of personnel from Site Engineering, Operations, and QA. Quality Instruction ENG-QI 6.7, "FSAR Reviews," was followed for the classification of the review findings. All chapters of the UFSAR for both units were reviewed by Engineering and Operations personnel. Procedures and procedural processes that were mentioned in the UFSAR were identified. Mutual consistency between the procedures and the UFSAR was established and the inconsistencies were identified and documented. After the licensee completed both UFSAR reviews, the inspector noted that recommendations for UFSAR corrections, procedure changes, and plant modifications (if required) were prioritized and scheduled for disposition.

The inspector noted that the results of the St. Lucie Unit 1 UFSAR/Procedure Consistency Review were documented in FPL inter-office correspondence JPN-SPSL-96-0560, dated December 30, 1996. This review resulted in a total of 41 CRs, 129 PMAIs, 206 Procedure Change Requests (PCR), and 80 FSAR Change Packages (FCP) being issued to document and track the findings. There were no Unit 1 modifications required as a result of this review.

The inspector noted that the results of the St. Lucie Unit 2 UFSAR/Procedure Consistency review were documented in FPL inter-office correspondence JPN-SPSL-96-0562, dated December 31, 1996. This review resulted in a total of 26 CRs, 181 PMAIs, 228 PCRs, and approximately 65 FCPs being issued to document and track the findings. The inspector noted that there was one Unit 2 modification which resulted from this review. A condition was identified by the licensee where an UFSAR commitment had not been met by the plant design in that the control power for the primary and the back-up protection for the Reactor Coolant Pump (RCP) feeders was being provided from the same battery. The licensee initiated Plant Change/Modification (PC/M) 97015, RCP Relaying Modification, to address this finding. This PC/M was classified by the licensee as being non-nuclear safety related.

The inspector further noted during review of the licensee's results that completion of the corrective actions for the UFSAR findings was not tied to the December 31, 1996, NRC commitment date. The licensee had developed workoff curves and schedules to track completion of all the findings.

The inspector concluded that the findings identified by the licensee during the UFSAR/Procedure Consistency Review were documented, processed, and being tracked in accordance with the licensee's corrective action program and NRC regulations.

UFSAR Graded Review

The inspector reviewed the FPL's letter L-97-180, Voluntary Initiative to Review Final Safety Analysis Reports, dated July 11, 1997. In this letter, FPL committed to conduct a graded review of the St. Lucie Unit 1 and Unit 2 UFSARs. This review by the licensee was being performed in accordance with the revisions that the NRC published to its General Statement of Policy and Procedures for Enforcement Actions, (Enforcement Policy), (NUREG 1600) to address issues associated with departures from the UFSAR. These revisions were published in the Federal Register (61 FR 54461) by the NRC on October 18, 1996.

In the July 11, 1997 letter, FPL indicated that the reviews would be prioritized according to risk significance (based on probabilistic safety assessment methods) of the systems described in the UFSAR sections. The licensee had established four priority levels. The licensee further indicated that the discovery phase of the Priority 1, 2, and 3 reviews was expected to be completed by October 18, 1998, but some of the walkdowns that require access to the containment buildings may be completed during the Unit 2 refueling outage in 1998 and the Unit 1 refueling outage in 1999. The licensee indicated that the Priority 4 systems may be reviewed, pending the outcome of the Priority 1, 2, and 3 reviews.

The inspector noted that the project scope for performing the UFSAR reviews was still being developed by the licensee at the conclusion of this inspection. The inspector noted that the scope document, titled "Review of Risk-Significant UFSAR Systems," dated July 16, 1997, was still in draft form. The inspector discussed the project scope with Site Engineering personnel who indicated that the UFSAR fire protection systems (which were described as Priority 2 systems in the July 11, 1997, letter) would be covered in a separate scope document.

The inspector concluded that the specific details of the licensee's plan to perform a graded review of the UFSAR systems according to risk significance (as discussed in the licensee's letter to the NRC dated July 11, 1997) were being developed.

c. <u>Conclusion</u>

The inspector concluded that the findings identified by the licensee during the UFSAR/Procedure Consistency Review were documented, processed, and being tracked in accordance with the licensee's corrective action program and NRC regulations.

The inspector also concluded that the details of the licensee's plan to perform a graded review of the UFSAR systems according to risk significance (as discussed in the licensee's letter to the NRC dated July 11, 1997) were being developed.

E8.2 <u>Condition Report Review (40500)</u>

a. <u>Inspection Scope</u>

The inspector reviewed selected CRs assigned to Site Engineering to assess the adequacy and timeliness of the corrective actions proposed by Engineering.

b. <u>Observations and Findings</u>

The inspector reviewed the CRs listed below that were assigned to Site Engineering for resolution. The inspector noted that Engineering had not responded to some of these CRs because the 30 day response due dates had not been reached at the time of this inspection.

CR 97-0494	CR 97-0524
CR 97-0592	CR 97-1211
CR 97-1399	CR 97-1414
CR 97-1422	CR 97-1428
CR 97-1429	CR 97-1460

During review of CR 97-1422, the inspector noted that this CR was written to document a concern that plant drawings were not revised when the Unit 2 PC/M 008-295, RPS NI Safety Channel Replacement, was revised during implementation via Change Request Notice (CRN) 008-295-5600. Site Engineering responded to the CR by issuing Drawing Change Request (DCR) 97-0127 to resolve the drawing configuration issue. The Engineering response to this CR also included corrective actions to address generic implications and actions to prevent recurrence. These actions included a PMAI (PM97-08-053) assigned to Engineering to review the CRNs, drawings, and manuals for both the Unit 1 and Unit 2 Nuclear Instrumentation (NI) modifications (PC/M 009-195 and PC/M 008-295, respectively). The inspector considered that the corrective actions for this CR were of sufficient depth and scope to address the issue identified. However, during further review of this CR, the inspector noted that the due date for completion of the PMAI was March 30, 1998. The inspector discussed this CR with licensee personnel and questioned the timeliness for completion of this PMAI, given the Unit 2 drawing configuration issues identified with implementation of CRN 008-295-5600, and the configuration control issues identified during implementation of the Unit 1 PC/M (discussed in NRC Inspection Report 50-335,389/96-22) in the Unit 1 refueling outage in 1996. Subsequent to the discussions with the inspector, the licensee revised the completion due date for PMAI PM97-08-053 from March 30, 1998 to November 30, 1997. The inspector informed the licensee that after the licensee completes the actions for PMAI PM97-08-053, the inspector will review the results during a subsequent inspection. Followup of this issue was identified as Inspector Followup Item, IFI 50-335,389/97-10-02, "Completion of Corrective Actions for Condition Report 97-1422 Regarding Plant Drawing Revisions."

During review of the other CRs, the inspector noted that Engineering generally provided acceptable responses to address the concerns identified in the applicable CR.

c. Conclusions

The inspector concluded that, for the condition reports reviewed, Site Engineering generally provided acceptable responses to address the concerns identified in the applicable condition reports. However, the initial due date for completing the corrective actions for CR 97-1422 was not considered timely. The completion date was revised by the licensee and an IFI was identified to review the completed corrective actions.

E8.3 (Closed) URI 50-335,389/96-04-09, "Failure to Update UFSAR"
(Closed) URI 50-335,389/96-15-05, "Inadequate Design Basis Documentation"
(Closed) URI 50-335/96-16-04, "FSAR Description of Installed Instrumentation on Unit 1 HSDP" (92903)

The inspector reviewed the NRC-identified UFSAR inaccuracies detailed in Table 1 in accordance with the Enforcement Policy as updated by Enforcement Guidance Memorandum (EGM) 96-005, "Enforcement Issues Associated with FSARs, Section 8.1.3 Enforcement of FSAR Commitments." With respect to the items in the table below, the inspector reviewed the licensee's planned UFSAR review effort to determine whether it was reasonable to conclude that the inaccuracies would have been identified by the licensee's review program. The inspector had the following findings associated with the items on the table:

- With respect to item 1, the inspector noted that, although the deficiency was identified to the licensee in an inspection report dated April 29, 1996, the inaccuracy was not corrected in a UFSAR amendment submitted in January, 1997. The licensee's failure to update the UFSAR in this case was found to be one example of a violation of 10 CFR 50.71(e), which required that the UFSAR be periodically updated to include the latest material developed (VIO 50-335,389/97-10-03, "NRC Identified UFSAR Inaccuracies").

- With respect to items 2 through 16 the inspector concluded that the inaccuracies would not have been identified by the licensee's documented UFSAR review effort and were, therefore, subject to enforcement action per the subject EGM. The inspector found that the subject items represented additional examples of violations of 10 CFR 50.71(e) (VIO 50-335,389/97-10-03, "NRC Identified UFSAR Inaccuracies").

- With respect to item 17, the inspector concluded that the item was identified shortly after a modification was affected that created the subject inaccuracy. The licensee subsequently incorporated the change appropriately.

- With respect to item 18, the inspector concluded that because manual operation of these components was only allowed under test conditions, an inaccuracy in the UFSAR did not exist.

- With respect to item 19, the licensee provided additional information indicating the UFSAR requirements were met.

- With respect to items 20, 21, and 22, the inspector concluded that the licensee's program to review the UFSAR was of sufficient scope to identify these examples. In accordance with the Enforcement Policy, the failure to update the UFSAR normally would be categorized as a Severity Level IV violation. However, as discussed in Section VII.B.3 of the Enforcement Policy, the NRC may refrain from issuing a Notice of Violation (Notice) for a violation that involves a past problem, such as an old engineering, design, or installation deficiency, provided that certain criteria are met. After review of this violation the NRC has concluded that while a violation did occur, enforcement discretion is warranted in this case. Therefore, to encourage licensee efforts to identify and correct UFSAR discrepancies, no Notice is being issued in this case. The specific bases for this decision were (1) the licensee's UFSAR review program, as described in paragraph E8.1.b of this report, would likely have identified the violation in light of the defined scope, thoroughness and schedule; (2) there had been no prior notice where the licensee could have reasonably identified the violation earlier; (3) timely and appropriate corrective action was taken or planned; (4) timely and effective long-term corrective actions are being implemented to review and identify any similar design deficiencies; (5) the design deficiency was considered an old design issue; and, (6) the violation was not willful. This issue will be documented as Non-Cited Violation (NCV) 50-335,389/97-10-06: Failure to Update UFSAR.

With respect to item 23, the inspector noted that the inaccuracy appeared to represent an inaccuracy of material significance. The issue's resolution has been tied to the resolution of a generic concern for the operability of containment leak detection radiation monitors. The issue will be tracked as a part of a separate URI, as discussed below. URI 50-335,389/96-04-09 is closed. URI 50-335/96-16-04 is closed.

TABLE 1

Item	IR	Paragraph	Discrepancy
1	96-004	X1	Unit 1 UFSAR Table 6.2-22 showed Unit 1 NaOH concentration as 30-32 w/o. TS 3.6.2.2.a correctly specified the concentration as 28.5-30.5 w/o.
2	96-006	X1.1	Unit 1 UFSAR Table 7.3-2 incorrectly designated MV-21-2 as relating to the A ICW train rather than the B ICW train.
3	96-006	X1.1	Unit 1 UFSAR Figure 9.2.1a was not revised following modifications to the intake cooling water lube oil cooler performed under PC/M 341-192.
4	96-006	X1.1	Unit 1 UFSAR Table 7.4-1, Intake Cooling Water System, was not revised to delete lubricating water pressure switches FIS-21-3A, 3B, 3C, 3D, 3E and 3F (non-safety) which had been removed by modification.
5	96-006	X1.1	Unit 1 UFSAR figures 7.4-9, 19, and 11 were not revised to remove annunciator E-15 logic, which was spared out.
6	96-006	X1.1	Unit 2 UFSAR Table 7.3-2 incorrectly designated MV-21-2 as relating to the A ICW train rather than the B ICW train.
7	96-006	X1.2	Unit 1 UFSAR Section 4.2.3.2.3(b)(1) indicated a minimum CEA drop time of 2.5 seconds plus 0.5 seconds totalling 3.0 seconds which was inconsistent with the 3.1 seconds listed in TS 3.1.3.4 and UFSAR Table 4.2-1.
8	96-006	X1.2	An audit of Unit 2 fire extinguishers identified three fire extinguishers, at locations T-13, T-16, and T-18 of the Turbine Building,that were not the types of fire extinguishers described in Unit 2 UFSAR Table 9.5A-8D.

Item	IR	Paragraph	Discrepancy
9	96-008	X1	Unit 2 UFSAR Table 7.5-3 for windows LA-9 and LB-9 incorrectly showed actuation devices as LS-17-552A/553A and LS-17-552B/553B. The correct actuation devices were LS-59-009A/014A and LS-59-21B/28B.
10	96-008	X1	Unit 2 UFSAR Table 7.5-3 indicated that windows LA-4 and LB-4. "Lube Water Supply Strainers High Differential Pressure. were safety related. The system had been downgraded to non-safety related status by PC/M 268-292.
11	96-015	E3.1	Unit 1 UFSAR Section 5.2.4.5.b.1 incorrectly stated that the level detector which measured leakage flow through the containment sump weir was non-seismic. The detector was in fact seismically qualified. [This section also stated that the recorder would have a full scale range of 0 to 11 gpm. The recorder. FR-07-03. in fact had a range of 0 to 12 gpm.]
12	96-015	E3.1	Unit 1 UFSAR Section 5.2.4.5.b.2 stated that the Containment Atmosphere Radiation Monitoring System took isokinetic samples of air from the containment cooling system ductwork. Section 12.2.4.1 stated that the sample nozzles were designed such that the sampling velocity was the same as that in the ventilation system so that preferential particulate selection did not occur. The licensee indicated that the system flow rate was greater than the sample flow rate: therefore the system was not isokinetic.
13	96-015	E3.1	Unit 1 UFSAR Table 5.2-11. Reactor Coolant Leak Detection Sensitivity. item (1). referenced Figure 5.2-36 which did not exist. [The Average Rate of Change and the Time for Scale to Move did not correspond for entries 2 and 3 of Table 5.2-11]. [Human factors decrepancies were identified in that the instrument ranges in Item (2) for the quench tank water level. Item (3) for Safety Injection Tank water level were specified in units that did not correspond to units used in the plant instrumentation. Also. item (3) indicated that the Safety Injection Tank pressure instruments ranged from 0 to 250 psig when plant instruments indicated from 0 to 300 psig.] [The licensee identified that the average rate of change did not corres[pond to item 2 and 3 of Table 5.2-11.]
14	96-015	E3.1	Unit 1 UFSAR Section 12.2.4.1 stated that containment atmosphere sample flow was regulated and indicated by independent mass flow meters. While the flow was indicated by independent mass flow meters. it was not regulated. The system flow was dependent only on the capability of the pump.
15	97-006	E8.8	Unit 1 UFSAR Table 8.3-5 did not match the battery load profile shown in calculation PSL-1-F-J-E-90-0015 and UFSAR Figure 8.3-14.
16	97-006	E8.8	UFSAR Table 9.2-5. Operating Flow Rates and Calculated Heat Loads for Auxiliary Equipment Cooled by Component Cooling Water. was not changed to reflect a 1993 accident reanalysis of these parameters.
17	96-004	X1	Unit 2 UFSAR Table 7.3-4 listed EDGs as starting on a CSAS: a feature removed in the Unit 2 outage previous to the finding.
18	96-006	X1.1	Unit 1 and 2 UFSAR descriptions of TCV 14-4A and 4B operation assume the valves to be automatic. yet procedures allow manual operation.
19	96-006	X1.1	Unit 2 UFSAR Section 9.2.1.2 stated that an alarm would alert operators if blowdown heat exchanger ICW isolation valves were reopened during a SIAS. The design of the alarm was unclear.
20	96-022	X.1	PC/M 009-195 deleted the rod drop turbine runback feature in Unit 1 NI circuitry. but UFSAR Section 7.7.1.4 was not updated to reflect the deletion.
21	URI 96-16-04 IR 96-16	02.3.6	Unit 1 UFSAR Section 7.4.1.8 listed one control switch for the pressurizer auxiliary spray valve as installed on the Hot Shutdown Panel. Two switches were actually installed.

Item	IR	Paragraph	Discrepancy
22	URI 96-16-04 IR 96-16	02.3.6	Unit 1 UFSAR Section 7.4.1.8 Hot Shutdown Panel contained two source range and two wide range NIs. The UFSAR failed to list the existence of these in lists of installed indicators.
23	96-015	E3.1	Unit 1 UFSAR Section 5.2.4.6 stated that the rate of change in indication of the various leak detection parameters provides the necessary information to identify and estimate reactor coolant system leakage rates for a 1.0 gpm leak. Table 5.2-11 lists the amount of time for a 1 gpm leak to be detected as evidenced by a 10 percent deviation in the normal readings. The inspector observed the Containment Radiation Particulate and Gaseous meters channels 31 and 32, respectively, to deviate by more than 10 percent normally, without a 1 gpm leak.

URI 50-335,389/96-15-05, "Inadequate Design Basis Documentation," was opened to track the resolution of questions raised over both units' leak detection system containment radiation monitors (Item 23 in Table 1). The issue was raised when the inspectors noted that no basis existed for containment particulate and gaseous air sampling high radiation alarm setpoints. Since the original inspection of this issue, the inspectors continued to review the subject systems' descriptions in the UFSAR and the licensee's actions relative to the systems. In the course of the inspection, the inspectors noted that the licensee had no analytical basis for the information in the UFSAR. Consequently, in October, 1996, the licensee began performing calculations to demonstrate the performance characteristics of both units' detectors. The inspectors identified discrepancies as described in Table 2 below:

TABLE 2

Unit	Source	Discrepant Information	Discussion
1	UFSAR 5.2.4.1	"The leakage detection systems are consistent with the recommendations in R.G. 1.45..."	Referenced Regulatory Guide stated that the sensitivity of each leakage detection system should be adequate to detect a leakage rate of 1 gpm in 1 hour. UFSAR information, described in items below, indicated that the UFSAR might be inaccurate in this regard. A Task Interface Agreement (TIA) on the subject was forwarded to NRR for review. The accuracy of the UFSAR statement will be judged, in the context of the requirements of 10 CFR 50.9, based upon the response to the TIA.

Unit	Source	Discrepant Information	Discussion
1	UFSAR 5.2.4.5	"The time that a 1.0 gpm reactor coolant boundary leak takes to cause a 10 percent deviation in the normal readings of various monitoring systems is listed in Table 5.2-11." The subject Table indicated that: The time for the gaseous monitor to deviate 10 percent was 15.1 hours. The time for the particulate monitors to deviate 10 percent was 18.1 hours	The inspectors found that normal deviations experienced in the unit resulting from fluctuations in background level exceeded 10 percent over several minutes. The accuracy of the UFSAR in indicating that a 10 percent deviation was both indicative of a 1 gpm leak and was, in fact, identifiable given background variability, will be evaluated in the context of 10 CFR 50.9. Calculation PSL-1FSN-96-002, Revision 0, which evaluated gaseous monitor sensitivity, indicated that a 10 percent increase in detector output could, mathematically, occur in 2.1 hours, assuming a higher percentage of failed fuel than currently existed in the plant. The calculation also stated that "It is unacceptable to use an alarm setpoint of two times background as an indication of a 1.0 gpm step increase in RCS leakage since the time to an alarm would be too long...[based on realistic RCS chemistry]." Estimates of times required to identify a 1 gpm leak based on typical chemistry, a 100 percent increase in indication, and initial leak rate (prior to a 1 gpm step increase) varied from 19 hours to 1200 hours. The corresponding times for a 10 percent change ranged from 2.1 hours to 19.5 hours. The calculation results (Section 6.2 of the calculation) stated that, given current RCS chemistry performance, "...there would be insufficient activity available in the containment atmosphere for the containment gaseous monitor to noticeably respond to a 1 gpm step increase in RCS leakage." Calculation PSL-1FSN-96-001, Revision 0, which evaluated particulate monitor sensitivity, indicated that a 100 percent increase in detector output could, mathematically, occur in 70 minutes. The calculation also stated that the use of the 10 percent deviation as indicative of 1 gpm RCS leakage was "difficult given the current operating environment."
2	UFSAR 5.2.5	"The leakage detection system is capable of detecting unidentified leakage equivalent to 1.0 gpm or less within one hour." Table 5.2-14 indicated that detection time for both the particulate and gaseous monitors to deviate 10 percent from normal readings were ">62 minutes."	Calculation PSL-2FSN-96-003, Revision 0, performed to evaluate the containment particulate monitor, concluded that, for typical chemistry conditions, 105 minutes were required for detector output to double. As in the case of Unit 1, a 10 percent increase in output was found, in the field, to be masked by the natural variability of background levels. The accuracy of the subject statement will be reviewed against the requirements of 10 CFR 50.9.
1	UFSAR 5.2.5	"The leakage detection system is consistent with the recommendations of Regulatory Guide 1.45..."	The inspectors noted that the referenced Regulatory Guide stated that the sensitivity of each leakage detection system should be adequate to detect a leakage rate of 1 gpm in 1 hour. UFSAR information, described in items below, indicated that the UFSAR might be inaccurate in this regard. A TIA on the subject was forwarded to NRR for review. The accuracy of the UFSAR statement will be judged, in the context of the requirements of 10 CFR 50.9, based upon the response to the TIA.

In addition to the discrepancies identified above, the inspectors identified a potential operability concern relating to the detectors. The applicable TS stated:

3.4.6.1 The following RCS leakage detection systems shall be OPERABLE:

a. The reactor cavity sump inlet flow monitoring system; and

b. One containment atmosphere radioactivity monitor (gaseous or particulate).

APPLICABILITY: MODES 1, 2, 3, and 4.

The inspectors noted that an obvious operability issue would exist if the licensee is found to be out of agreement with the Regulatory Guide referred to in the UFSARs. However, the inspectors also questioned whether the monitors could be considered operable if RCS activity levels were less than that assumed in the UFSAR (.1 percent failed fuel). Specifically:

- Current chemistry results indicate that the units are performing much better, relative to failed fuel, than assumed in the UFSAR. Calculations referred to above indicate that the low level of RCS activity presents a challenge in the ability of the detectors to identify leakage.

- Both units' particulate monitor calculations credit Rubidium-88 (Rb-88) alone as providing the activity detected. Rb-88 has a half-life of approximately 18 minutes. Given this short half-life, the inspectors questioned the ability of the particulate monitors to indicate leakage when the unit is in Modes 3 and 4. For example, a simple decay law estimation indicated that Rb-88 activity levels 24 hours after shutdown would reduced by a factor of approximately 8E-25.

When asked for a basis for Mode 3 and 4 operability, the licensee stated that meeting the recommendations of Regulatory Guide 1.45 as stated in the UFSAR and accepted in two NRC Safety Evaluation Reports was sufficient to establish operability regardless of plant mode. Additionally, the licensee stated that surveillance requirements of the subject TS were met (the monitors were calibrated and channel checks were performed as required), thus indicating operability. The inspectors noted that the Bases for TS 4.03 stated, in part, "Under the provisions of this specification, systems and components are assumed to be OPERABLE when Surveillance Requirements have been satisfactorily performed within the specified time interval. However, <u>nothing in this provision is to be construed as implying that systems and components are OPERABLE when they are found or known to be inoperable although still meeting the Surveillance Requirements</u> [emphasis added]." The operability of the subject monitors will be resolved as a part of the overall issue.

In addition to the issues above, the inspectors noted that, while the lack of calculations which supported statements made in the UFSAR was identified to the licensee in October of 1996, the licensee had, at the close of the current

inspection period, failed to complete the calculations. The calculations for Unit 1 were completed on October 24, 1996. The calculation for the Unit 2 particulate monitor was completed on February 4, 1997. The licensee stated that the Unit 2 gaseous monitor calculation was not scheduled to be completed until approximately January, 1998. The inspectors asked whether Safety Evaluations under 10 CFR 50.59 had been performed for the noted UFSAR discrepancies. The licensee stated that none had been performed and that they would not be performed until the calculations were complete. The timeliness of the licensee's corrective actions (completion of calculations which support UFSAR data and operability and the performance of 10 CFR 50.59 Safety Evaluations) will be reviewed for conformance to 10 CFR 50 Appendix B, Criterion XVI, to determine whether the licensee's actions were of appropriate promptness.

The issues described above will be tracked as one URI (URI 50-335,389/97-10-04, "RCS Leakage Detection Radiation Monitor Acceptability and Operability"). URI 50-335,389/96-15-05, "Inadequate Design Basis Documentation," will be closed in deference to the new URI, which incorporates design basis, operability, UFSAR accuracy, and corrective action issues.

IV. Plant Support

F2 Status of Fire Protection Facilities and Equipment

F2.1 Emergency DC Light (71750)

a. Inspection Scope

The inspector performed a walkdown of the Emergency DC lights within the Radiological Controlled Area (RCA) and observed portions of the monthly emergency lighting preventive maintenance.

b. Observations and Findings

On September 3, the inspector performed a partial walkdown of the RCA emergency lights, concentrating mainly on both RABs and the EDG rooms. The inspector noted deficiency tags on several lights, however, none of the tags noted were more than two months old. The following day, the inspector noticed an electrician performing the August checks per Procedure MP 0940066, Revision 20, "Portable Emergency Lighting Maintenance and Inspection," and Work Order 97017406. The results of the checks observed were satisfactory.

The inspector reviewed the last two months of inspections performed by Electrical Maintenance (EM). In July, four lighting units were found to be inoperable in Unit 1 and replaced (EL-1-36-001, EL-1-36-004, EL-1-47-002, and EL-1-7-006). EM found nine emergency lights that needed replacement in Unit 2. Planning has issued a work order to replace these lights when replacement batteries become available. The inspector noted that the generic work order to check the lights also allowed replacing lights. In fact, one step stated that ten spares should be on hand. When the inspector questioned why there were no spares, the EM

supervisor and the planner stated that the had an unusually high usage recently and all spares had been used.

c. Conclusions

The PM program for the DC emergency lighting system is adequate to detect any problems with the lights within approximately one month of failure. Several lights were noted to need replacement, work had been planned and replacement batteries were on order.

F2.2 Fire Pump Walkdown (71750)

a. Inspection Scope

On August 26, the inspector performed a detailed walkdown of the fire pump area. The inspector was looking for any detrimental conditions, system lineup, and licensing document conformance.

b. Observations and Findings

The inspector had questions about multiple items, most of which the licensee proved acceptable to the inspector. However, the licensee did agree that several items required some type of corrective action. The inspector identified that all of the large Motor Operated Valves (MOV) had equalizing valves installed around the MOV. Drawing 8770-G-084 SH. 1 did not show the equalizing lines and valves. Engineering verified that the original design included one inch bypass valve features, and therefore no design non-conformance or operability concerns existed. CR 97-1670 documented the drawing problem and requested Engineering and Operations Support to initiate a revision to the drawing.

The inspector also noticed that the large MOVs were all locked open or closed. Drawing 8770-G-084 SH. 1 did not show any locking devices present. Protection Services recognized that this question had been asked in the past. Inspection Report 95-21 noted that V15500 was shown closed, but the actual position was locked closed. At that time, the licensee initiated STAR 960264 to investigate. The response indicated that this was an acceptable practice. Nuclear Engineering Standard, STD-D-13.5, Paragraph 6.12 stated that, "Valves shall be indicated as locked open or locked closed when as a Design Baseline, locks are necessary for nuclear or personnel safety. Valves locked administratively for equipment security and other similar purposes are not to be addressed on Flow Diagrams." The STAR further stated that the licensee locks the valves to meet Nuclear Mutual Limited Insurance Standards and National Fire Protection Association Standards. Since no design baseline exists to maintain these valves in a locked position for nuclear or personnel safety, the drawings do not need to show the valves as locked.

The inspector noted that both pumps had discharge pressure switches (PS-15-20 for 1A and PS-15-21 for 1B) and pressure gages (PI-15-24A for 1A and PI-15-24B for 1B) that had several temporary valves associated with them. The Protection Services Supervisor agreed that the valves were necessary to use the system and that they would not remove them. An Engineering review revealed that these valves met the definition of a temporary valve per Operations Instruction 0-OI-99-09, Revision 0, "Labeling/Tagging of Plant Equipment," and they were properly labeled.

The inspector observed what appeared to be caulking around the base of three 1B fire pump pipe supports. Protection Services stated that the caulking was placed around the edge to keep water from corroding the support flange from underneath. The inspector questioned if the concrete support pad actually made contact with the pipe support. The inspector and the Protection Services Manager probed behind the caulk and found that the support flange on the discharge of the 1B pump was not in contact with the concrete support. The Protection Services Supervisor wrote a CR (97-1695) to determine the operability of the system. Engineering determined that the support was not required and that the system was operable. The preliminary analysis showed that all pipe stresses were within allowable limits and no operability concerns existed. Engineering was planning to continue their investigation to learn how the piping was left in this condition.

The inspector performed an independent investigation in an attempt to determine the reason for this nonconformance. In October, 1996, the licensee replaced the 1B pump casing due to excessive corrosion according to PWO 69 5085. Although the workers remember some "difficulty" in pipe/pump flange alignment, the Journeyman's notes only discussed shimming the pump to meet the discharge flange. The licensee completed a similar replacement on the 1A pump in February, 1997. Again the workers noted some pipe fitup problems, and again they documented shimming the pump. None of the maintenance personnel interviewed by the inspector remembered noticing the gap between the support and the support base. The inspector was unable to determine when the support was lifted, but it may have been prior to the pump casing replacement.

The inspector spoke with the painter who caulked and painted the supports. He stated that his painting guidelines directed him to caulk any cracks prior to painting. He further stated that he did not consider that a problem might exist if the support did not rest on the base. Once the painter painted the support, the inspector concluded that it was unlikely that a casual observer would notice that the supports were caulked and painted.

The inspector noticed that the pipe around the 1B recirculation check valve V15121 was not painted and was heavily corroded. The licensee confirmed that they had recently performed work on the check valve and they never repainted the carbon steel pipe. The licensee corrected the condition.

c. Conclusions

The inspector found the overall condition of the fire pumps to be acceptable. The system was properly lined up for standby actuation.

One deficiency was identified due to a pipe support found not supporting the pipe. Some other minor deficiencies were noted and corrected or planned to be corrected. With the exception of leaving a repaired check valve exposed to the environment, the inspector found the material condition generally good.

F5 Fire Protection Staff Training and Qualification

F5.1 (Closed) URI 50-335,389/97-06-13 "Failure to Man the Fire Brigade as Required by Procedure" (92904)

This Unresolved Item involved an Auxiliary Nuclear Plant Operator (ANPO) filling a position on the fire brigade team which was specifically designated as requiring a Senior Nuclear Plant Operator. The procedure was not changed prior to allowing the ANPO to assume the SNPO's fire brigade duties. Further investigation determined that the ANPO did meet the intent of the procedure; he had been trained in Safe Shutdown System fire fighting and was a qualified brigade member. Operations supervision did not question the one specific requirement that the position was to be filled by a SNPO. Procedure QI-5-PSL-1, Revision 2, "Preparation, Revision, Review/Approval of Procedures," Section 4.7.1, required verbatim compliance with procedures. This failure to follow the procedure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, NCV 50-335,389/97-10-05, "Failure to Man the Fire Brigade as Required by Procedure," consistent with Section IV of the NRC Enforcement Policy. This item was inadvertently reported in the items opened and closed section of Inspection Report 97-06 as a NCV. It was unresolved at the end of that report period. This Unresolved Item is now closed.

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 September 12, 1997. An interim exit meeting was held on August 22, 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 37550:	Engineering
IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 42700:	Plant Procedures
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92901:	Followup - Plant Operations
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-335,389/97-10-01	NCV	"Failure to Update a Procedure" (Section 03.1)
50-335,389/97-10-02	IFI	"Completion of Corrective Actions for Condition Report 97-1422" (Section E8.2)
50-335,389/97-10-03	VIO	"NRC Identified UFSAR Inaccuracies" (Section E8.3)
50-335,389/97-10-04	URI	"RCS Leakage Detection Radiation Monitor Acceptability and Operability" (Section 08.3)
50-335,389/97-10-05	NCV	"Failure to Man the Fire Brigade as Required by Procedure" (Section F5.1)
50-335,389/97-10-06	NCV	"Failure to Update UFSAR" (Section E8.3)

Closed

50-389/96-001-00	LER	"Manual Reactor Trip Due to High Main Generator Cold Gas Temperature" (Section 08.1)
50-335/96-003-00	LER	"Containment Particulate and Gaseous Monitor Out of Service Resulting in a Condition Prohibited by Technical Specifications Due to Personnel Error" (Section 08.2)
50-335/96-004-00	LER	"Inadvertent Manual Start of the 1A Emergency Diesel Generator Due to Personnel Error" (Section 08.3)
50-335,389/96-11-04	VIO	"Preconditioning of Valves Prior to Surveillance" (Section 08.4)
50-335,389/96-16-02	VIO	"Failure to Control Operation Keys" (Section 08.5)
50-335,389/96-04-09	URI	"Failure to Update UFSAR" (Section E8.3)
50-335,389/96-15-05	URI	"Inadequate Design Basis Documentation" (Section 08.3)
50-335/96-16-04	URI	"FSAR Description of Installed Instrumentation on Unit 1 HSDP" (Section E8.3)
50-335,389/97-06-13	URI	"Failure to Man the Fire Brigade as Required by Procedure" (Section F5.1)

Discussed

50-335/96-04-01	VIO	"Failure to Follow Procedures Lead to Unit 1 Containment PIG Inoperability" (Section 08.2)
50-335,389/96-15-05	URI	"Inadequate Design Basis Documentation" (Section 08.2)
50-335,389/97-04-02	VIO	"Routine Use of Heavy Operator Overtime" (Section 03.1)

LIST OF ACRONYMS USED

ADM	Administrative Procedure
AFW	Auxiliary Feedwater
ANPO	Auxiliary Nuclear Plant [unlicensed] Operator
ANPS	Assistant Nuclear Plant Supervisor
AP	Administrative Procedure
ARP	Annunciator Response Procedures
ATTN	Attention
CEA	Control Element Assembly

CFR	Code of Federal Regulations
CR	Condition Report
CRN	Change Request Notice
CSAS	Containment Spray Actuation System
CVCS	Chemical & Volume Control System
CWD	Control Wiring Diagram
DC	Direct Current
DCR	Drawing Change Request
DPR	Demonstration Power Reactor (A type of operating license)
DWG	Drawing
EA	Enforcement Action
EDG	Emergency Diesel Generator
EGM	Enforcement Guidance Memorandum
EM	Electrical Maintenance
EMP	Electrical Maintenance Procedure
ENG	Engineering
EOP	Emergency Operating Procedure
EP	Engineering Package
ERT	Event Response Team
FCP	UFSAR Change Package
FPL	The Florida Power & Light Company
FR	Federal Regulation
FRG	Facility Review Group
FSAR	Final Safety Analysis Report
GDT	Gas Decay Tanks
HP	Health Physics
HPSI	High Pressure Safety Injection (system)
HSDP	Hot Shutdown Panel
I&C	Instrumentation and Control
ICW	Intake Cooling Water
IFI	[NRC] Inspector Followup Item
IP	Inspection Procedure
IR	[NRC] Inspection Report
ISEG	Independent Safety Engineering Group
IX	Ion Exchanger
JPN	(Juno Beach) Nuclear Engineering
LER	Licensee Event Report
LPSI	Low Pressure Safety Injection (system)
LS	Level Switch
M&TE	Measuring & Test Equipment
MOV	Motor Operated Valve
NaOH	Sodium Hydroxide
NCV	Non Cited Violation (of NRC requirements)
NI	Nuclear Instrument
NOV	Notice of Violation (of NRC requirements)
NPF	Nuclear Production Facility (a type of operating license)
NPO	Nuclear Plant Operator
NPS	Nuclear Plant Supervisor
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NUREG	Nuclear Regulatory (NRC Headquarters Publication)
NWE	Nuclear Watch Engineer

ONOP	Off Normal Operating Procedure
OP	Operating Procedure
PA	Public Address
PC/M	Plant Change/Modification
PCR	Procedure Change Request
PDR	NRC Public Document Room
PIG	Particulate-Iodine-Noble Gas Monitor
PM	Preventive Maintenance
PMAI	Plant Management Action Item
PORV	Power Operated Relief Valve
ppm	Parts per Million
psig	Pounds per square inch (gage)
PSL	Plant St. Lucie
PWO	Plant Work Order
QA	Quality Assurance
QC	Quality Control
QI	Quality Instruction
QSL	Quality Surveillance Letter
RAB	Reactor Auxiliary Building
Rb-88	Rubidium-88
RCA	Radiologically Controlled Area
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RDT	Reactor Drain Tank
RE	Reactor Engineering
RII	Region II - Atlanta, Georgia (NRC)
RPS	Reactor Protection System
SG	Steam Generator
SGRP	Steam Generator Replacement Project
SGT	Steam Generating Team, Ltd
SIAS	Safety Injection Actuation System
SNPO	Senior Nuclear Plant [unlicensed] Operator
St.	Saint
SSB	South Service Building
STAR	St. Lucie Action Request
TC	Temporary Change
TCV	Temperature Control Valve
TCW	Turbine Cooling Water
TEDB	Total Equipment Data Base
T_H	RCS Hot Leg Temperature
TIA	Task Interface Agreement
TQAR	Topical Quality Assurance Report
TRA	Technical Review and Assessment
TS	Technical Specification(s)
TSA	Temporary System Alteration
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
umho/cm	Micromhos per centimeter
URI	[NRC] Unresolved Item
USNRC	United States Nuclear Regulatory Commission
V	Volt(s)
VCT	Volume Control Tank

VIO	Violation (of NRC requirements)
VOTES	Valve Operation Test Evaluation System
WO	Work Order