UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-335/95-18 and 50-389/95-18

Licensee: Florida Power & Light Co
9250 West Flagler Street
Miami, FL 33102

Docket Nos.: 50-335 and 50-389 License Nos.: DPR-67 and NPF-16

Facility Name: St. Lucie 1 and 2

Inspection Conducted: September 17 through October 28, 1995

Lead Inspector: Edwin Lea, Jr. for RP — 11/24/95
R. Prevatte, Senior Resident Inspector — Date Signed

M. Miller, Resident Inspector
S. Sandin, Senior Operations Officer, AEOD

Approved by: K. Landis — 11/27/95
K. Landis, Chief — Date Signed
Reactor Projects Branch 3
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection was conducted onsite in the areas of plant operations review, maintenance observations, surveillance observations, engineering support, plant support, followup of previous inspection findings, and other areas.

Inspections were performed during normal and backshift hours and on weekends and holidays.

Results:

Plant operations area:

Two violations involving; inadequate log keeping and status control of the valve/switch duration log (2 examples), paragraph 3.A., and performing hazardous work on a system without implementing a required clearance were identified, paragraph 3.A. A weakness involving a log keeping deficiency that was not entered into the licensee corrective action program when identified. An additional weakness involving the failure to properly back out of an incorrect procedure resulted in discharging steam generator blowdown water to the roof of the reactor auxiliary building. A problem involving leaking pressurizer safety valves and misaligned tailpiping resulted in extensive engineering analysis, valve rework and detailed piping alignment to permit Unit 1 restart. The startup of Unit 1 after the

9512120054 951127
PDR ADOCK 05000335
G PDR

intended short notice outage was slow, cautious and methodical. The shutdown of Unit 2 for a refueling outage was slowed by the large number of needed procedural changes, but proceeded slowly and methodically without incident.

Maintenance and Surveillance area:

A violation involving design inadequacies in the Emergency Diesel Generator governor control logic was discovered during ESF Integrated Safeguards Testing, paragraph 4.b. Two non-cited violations involving missed surveillances on control element assembly position indication and reactor coolant system shutdown boron chemistry samples were identified and corrected by the licensee, paragraph 4.b. An additional non-cited violation involving incore instrument wiring discrepancies that occurred during the previous refueling outage was identified and corrected by the licensee, paragraph 4.a.

Problems involving load oscillations during surveillance testing on the Emergency Diesel Generators resulted in extensive troubleshooting and repairs to the governor controls. Assistance was obtained from equipment vendors to analyze, repair the problems, and assist in developing equipment maintenance program upgrades, paragraph 4.a.

Engineering area:

Licensee performance in this area was satisfactory.

Plant Support area:

Performance in the fire protection, physical protection, and radiological protection areas continued to be satisfactory.

Within the areas inspected, the following violations were identified:

VIO 335/95-18-01, "Failure to Follow Procedures and Maintain Current and Valid Log Entries in the Rack Key Log and Valve Switch Deviation Log," paragraph 3.a.

VIO 335/95-18-02, "Failure to Follow Clearance Procedures," paragraph 3.c.

VIO 389/95-18-03, "Failure to Adequately Design and Test the Emergency Diesel Generator 2 A/B Engineered Safety Feature Control Logic," paragraph 4.b.

Within the areas inspected, the following non-cited violations were identified associated with events reported by the licensee:

NCV 389/95-18-04, "Inadequate Verification of ICI Wiring Connections After Reassembly," paragraph 4.a.

NCV 335/95-18-05, "Missed Surveillance on CEA Position Indication," paragraph 4.b.

NCV 389/95-18-06, "Missed RCS Boron Concentration Surveillance During Mode 6," paragraph 4.b.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

* R. Ball, Mechanical Maintenance Supervisor
* W. Bladow, Site Quality Manager
* L. Bossinger, Electrical Maintenance Supervisor
* H. Buchanan, Health Physics Supervisor
* C. Burton, Site Services Manager
R. Dawson, Licensing Manager
* D. Denver, Site Engineering Manager
J. Dyer, Maintenance Quality Control Supervisor
* H. Fagley, Construction Services Manager
* P. Fincher, Training Manager
R. Frechette, Chemistry Supervisor
* P. Fulford, Operations Support and Testing Supervisor
* J. Geiger, Vice President, Nuclear Assurance
* J. Goldberg, President, Nuclear Division
K. Heffelfinger, Protection Services Supervisor
* J. Marchese, Maintenance Manager
* R. Olson, Instrument and Control Maintenance Supervisor
W. Parks, Reactor Engineering Supervisor
* C. Pell, Outage Manager
* L. Rogers, System and Component Engineering Manager
* D. Sager, St. Lucie Plant Vice President
* J. Scarola, St. Lucie Plant General Manager
* J. West, Operations Manager
C. Wood, Operations Supervisor
* W. White, Security Supervisor

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

NRC Personnel

* S. Ebneter, Regional Administrator, Region II
* K. Landis, Chief, Reactor Projects Branch 3
E. Lea, Project Engineer, Region II
* G. Meyer, Acting Region II Coordinator, EDO Office
* M. Miller, Resident Inspector
* J. Norris, Senior Project Manager, NRR
* R. Prevatte, Senior Resident Inspector
* S. Sandin, Senior Operations Officer, AEOD

* Attended exit interview

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

2. Plant Status and Activities

   a. Unit 1 restarted from a 73 day unplanned outage on October 12 and operated at essentially full power for the report period.

   b. Unit 2 shut down for a planned 49 day refueling outage on October 9 and remained in that outage for the remainder of the report period.

   c. NRC Activity

   R. Carrion, a health physics inspector from Region II, visited the site during the week of October 16. His inspection efforts are documented in IR 95-19.

   S. Ebneter, Region II Regional Administrator, K. Landis, Region II Branch Chief, St. Lucie Plant, G. Meyer, Acting Region II Coordinator, EDO Staff, and J. Norris, St. Lucie Project Manager, NRR, visited the site on November 1 for a St. Lucie Plant Improvement Program Status meeting.

3. Plant Operations

   a. Plant Operations Review (71707)

   The inspectors periodically reviewed shift logs and operations records, including data sheets, instrument traces, and records of equipment malfunctions. This review included control room logs and auxiliary logs, operating orders, standing orders, jumper logs, and equipment tagout records. The inspectors routinely observed operator alertness and demeanor during plant tours. They observed and evaluated control room staffing, control room access, and operator performance during routine operations. The inspectors conducted random off-hours inspections to ensure that operations and security performance remained at acceptable levels. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures. Control room annunciator status was verified. Except as noted below, no deficiencies were observed.

   1) On October 4, 1995, during a routine review of Unit 1 Control Room Logs, the inspector noted that the AFAS AB BYPASS SWITCH (Key #21) was listed in the Appendix C Valve Switch Deviation Log as being in BYPASS for SG Draining conducted on September 30. The RCO stated that this switch was placed in the BYPASS position when the electrical leads for the AFW PP 1A and AFW PP 1B were lifted per step 8.3.1 of Operating Procedure No. 1-0120027, Rev 21, "Steam Generator Cooling and Wet Lay-Up." The BYPASS position was designed to block the AFAS signal for actuation of the 1C AFW PP. The 1C AFW PP was out-of-service at the time due to plant conditions. A review of the control board showed the switch position to be in the NORMAL position. Discussion with the RCO determined that the log entry should have been closed out when the switch was restored to the NORMAL

position. The RCO verified the location of Key #21 and closed out the Deviation Log entry.

The inspector reviewed the archived Appendix B Rack Key Log for September 30 and found no entry for Key #21 check out.

AP 1-0010123, Rev 99, "Administrative Controls of Valves, Locks, and Switches," required:

a) that "All valve or switch position deviations or lock openings shall be documented in Appendix C Valve Switch Deviation Log...". [step 8.1.6]

b) that "The NPS/ANPS/NWE shall ensure that the verification of the status of all valves, locks and switches under Administrative Control is performed at the required intervals specified in AP 1-0010125...[step 8.3.1] which "Verifies that log entries are current and valid". [step 8.3.2.3]

c) that "A log of keys issued shall be maintained by the ANPS for the Controlled Key Locker...Appendix B, Rack Key Log". [step 8.2.2]

Step 8.1.2.R of AP 1-0010125 required review of the Valve/Switch Deviation Log each Midnight shift while in modes 1 through 6. Check Sheet #2 step 19 required the ANPS "Review the Valve/Switch Deviation Log to ensure that no valves or switches were in an alignment that would cause a Tech. Spec. LCO to be exceeded". Step 8.3.2 of AP 1-0010123 states that "The periodic verification of the status of valves, locks and switches under Administrative Control serves the following purposes:

1. Confirms that proper tags or locking devices are in place."

2. Ensures that all safety system main flow path valves are properly aligned and the valves are maintained in an operable condition.

3. Verifies that log entries are current and valid."

The periodic verifications of the Valve/Switch Deviation Log as documented by Check Sheet #2 step 19 were completed on October 1 through October 4. However; due to the somewhat narrow scope of the verification, i.e. "Review the Valve/Switch Deviation Log to ensure that no valves or switches are in an alignment that will cause a Tech. Spec. LCO to be exceeded", the fact that the AFAS BYPASS SWITCH position was neither current or valid was overlooked. The inspector identified this as a procedural inconsistency.

On October 5, the inspector questioned the ANPS regarding the corrective action taken for this occurrence. The ANPS stated that discrepancies of this nature could be reported to the operations supervisor using Data Sheet #7 of AP 0010120, Rev 75, although, in this instance, no such report was made. The inspector discussed this situation with the operations supervisor. The operations supervisor agreed with the inspector that Data Sheet #7 was NOT meant to replace or circumvent any other required reporting or corrective process as stated in Appendix B Shift Operations Policies of the procedure. The operations supervisor pointed out that when valves, locks or switches under administrative control are repositioned by a procedure, no Valve/Switch Deviation Log entry is required. In this case, the operations supervisor stated that operators should have initiated a TC to OP 1-0120027, Rev 21, to reposition the AFAS AB BYPASS Switch.

The safety significance of this occurrence was minimal. However, the inspector considered the failure of the licensee to document this problem, and followup with corrective actions, a program weakness. On October 17, a TC to AP 1-0010123, Rev 99, "Administrative Controls of Valves, Locks, and Switches" was incorporated which required that the STA periodically review Appendix C entries, report any discrepancies to the ANPS and document the review in a new Appendix to the same procedure. The inspector questioned this corrective action since "periodically" could mean once a shift, or a month, or year, and did not provide verifiable corrective action.

The failure to document when Key #21 was issued/returned and maintain current and valid log entries is one example of a violation, VIO 335/95-18-01, "Failure to Follow Procedures and Maintain Current and Valid Log Entries in the Rack Key Log and Valve Switch Deviation Log". A similar occurrence was documented in IR 95-15.

2) On October 11, 1995, during a routine review of Unit 2 Control Room Logs, the inspector found that the AFAS CABINET DOOR D (Key #202) was listed in the Appendix C Valve Switch Deviation Log as being OPEN for I&C Troubleshooting conducted on October 7. A discussion with the RCO determined that the log entry should have been closed out indicating the LOCKED CLOSED restored position. The RCO verified the location of Key #202 and closed out the Deviation Log entry.

The inspector reviewed the archived Appendix B Rack Key Log between October 7 and 11 and noted the following:

a) On October 7, there were 2 Log entries that showed the AFAS CABINET DOOR D was open from 5:10 PM to 5:27 PM and 5:30 PM to 5:35 PM for I&C Troubleshooting.

The Appendix C Valve/Switch Deviation Log showed only that the AFAS CABINET DOOR D was opened at 5:10 PM.

b) On October 10, there were 2 Log entries that showed the AFAS CABINET DOORS were open from 8:20 AM to 2:00 PM and 2:35 PM to 4:10 PM for AFAS Testing.

No Appendix C Valve/Switch Deviation Log entries were made since the AFAS CABINET DOORS were opened IAW OP 2-0400050, Rev 16, "Periodic Test of the Engineered Safety Features". However, this same OP required that "The following logs will be reviewed prior to the performance of applicable test sections...The Valve Switch Deviation Log." [step 5.3.1]. The inspector noted that this AFAS testing should have identified the open Appendix C Valve/Switch Deviation Log entry.

AP 2-0010123, Rev 68, "Administrative Controls of Valves, Locks, and Switches," required:

a) that "All valve or switch position deviations or lock openings shall be documented in Appendix C Valve Switch Deviation Log...". [step 8.1.6]

b) that "The NPS/ANPS/NWE shall ensure that the verification of the status of all valves, locks and switches under Administrative Control is performed at the required intervals specified in AP 2-0010125...[step 8.3.1] which "Verifies that log entries are current and valid". [step 8.3.2.3]

The periodic verifications of the Valve/Switch Deviation Log as documented by Check Sheet #2 step 25 were completed on October 8 and 9, however, due to the somewhat narrow scope of the verification, i.e. "Review the Valve/Switch Deviation Log to ensure that no valves or switches are in an alignment that will cause a Tech. Spec. LCO to be exceeded", the fact that the AFAS CABINET DOOR D log entry was neither current nor valid was overlooked. The inspector identified this as a procedural inconsistency.

The safety significance of this occurrence is minimal. However, the repeated missed opportunities to identify and correct this problem appears to be a significant weakness. On October 17, a TC to AP 2-0010123, Rev 68, "Administrative Controls of Valves, Locks, and Switches" was incorporated which required that the STA periodically review Appendix C entries, report any discrepancies to the ANPS and document the review in a new Appendix to the same procedure.

The failure to maintain current and valid log entries is the second example of violation, VIO 389/95-18-01, "Failure to

Follow Procedures and Maintain Current and Valid Log Entries in the Rack Key Log and Valve Switch Deviation Log."

b. Plant Tours (71707)

The inspectors periodically conducted plant tours to verify that monitoring equipment was recording as required, equipment was properly tagged, operations personnel were aware of plant conditions, and plant housekeeping efforts were adequate. The inspectors also determined that appropriate radiation controls were properly established, critical clean areas were being controlled in accordance with procedures, excess equipment or material was stored properly, and combustible materials and debris were disposed of expeditiously. During tours, the inspectors looked for the existence of unusual fluid leaks, piping vibrations, pipe hanger and seismic restraint settings, various valve and breaker positions, equipment caution and danger tags, component positions, adequacy of fire fighting equipment, and instrument calibration dates. Some tours were conducted on backshifts. During plant tours, the inspector also verified that the posting of required notices to workers were in place at the required locations. The frequency of plant tours and control room visits by site management was noted.

The inspectors routinely conducted main flow path walkdowns of ESF, ECCS, and support systems. Valve, breaker, and switch lineups as well as equipment conditions were randomly verified both locally and in the control room. The following accessible-area ESF system and area walkdowns were made to verify that system lineups were in accordance with licensee requirements for operability and equipment material conditions were satisfactory:

- Unit 1 Shutdown Cooling Trains A and B

  On October 4 and 5, the inspector conducted a walkdown of the Unit 1 Shutdown Cooling (SDC) System. Both trains were in service, however, train "B" was considered inoperable pending completion of administrative requirements following repairs to V-3651. All valves were found to be in the correct alignment for current plant conditions. Several discrepancies were noted:

  a) A PWO Tag with an attached Contamination Control Catch Device Tag was adrift underneath V-3935 in the LPSI Pump Room "1B".

  b) A puddle of clear fluid had collected under the LPSI "1A" Pump casing near V-3671 in the LPSI Pump Room "1A".

  The inspector notified HP of the above discrepancies. An HP tech accompanied the inspector to both LPSI Pump Rooms and also to provide access to both SDC Heat Exchanger Rooms as part of the SDC System walkdown. A swipe of the fluid taken by the HP tech appeared to be oil which was contaminated (18,000 dpm/100 cm^2). The HP tech could not identify the proper location for the tags adrift inside the roped-off HRA.

- Unit 2 Shutdown Cooling Trains A and B

On October 26, the inspector conducted a walkdown of the Unit 2 Shutdown Cooling System. A core offload was in progress at the time with train A isolated for outage work and train B in service. All train B valves were found to be in the correct alignment for current plant conditions.

The inspector reviewed both OP 2-041002, Rev 20, "Shutdown Cooling" and ONOP 2-0440030, Rev 26, "Shutdown Cooling Off-Normal," verifying correct valve/control switch nomenclature. OP 2-041002, Rev 20, "Shutdown Cooling," had several TCs inserted as part of the licensee's procedural upgrade program. The inspector, however, identified to the RCO an inconsistency between OP 2-041002, Rev 20, "Shutdown Cooling," and ONOP 2-0440030, Rev 26, "Shutdown Cooling Off-Normal." Section 7.2 of the OP placed SDC system in service. Within the section, step 7.2.4 had a NOTE saying "V-3545 (Hot-Leg Suction Cross-tie) is normally closed." This valve can be used to provide flow during off-normal conditions and must be OPEN if both SDC trains are in service". Other sections of the OP control the position of V3545 to ensure that it is closed for single train SDC. Step 7.2.10 of ONOP 2-0440030, Rev 26, "Shutdown Cooling Off-Normal," stated in Subsequent Operator Actions, "Ensure proper Shutdown Cooling Systems alignment per Appendix C, 'SDC System Alignment." Appendix C of the ONOP identified V3545 as OPEN. This did not recognize single train SDC operation for existing plant conditions. The RCO said this inconsistency would be addressed in a TC to the ONOP.

c. Operational Events

1) Circulating Water Box Clearance

On September 15, during condenser waterbox cleaning on Unit 2, the 2B2 waterbox manway was observed to be leaking following the start of 2B2 circulating water pump after waterbox cleaning. A decision was made to replace the manway gasket.

The mechanical maintenance foreman working this job informed the ANPS that parts were in hand and the gasket replacement would take about 20 minutes. The ANPS and maintenance foreman decided that a clearance would not be required as long as operators were stationed at both the local circulating water pump pushbutton station and at the control switch on RTGB 202, to prevent inadvertent pump start.

At 11:41 p.m., the 2B2 CWP was stopped. OP 2-0620020, Rev 26, "Circulating Water Normal Operating Procedure," Step 4.14, stated that, if CW pumps were being shutdown one at a time for waterbox cleaning, section 8.8 of the above procedure was to be used. Step 8.8.4 stated that a green flag on the CW pump control switch in the control room indicated that the waterbox vacuum breaker would open and the steam supply valve to the waterbox primary would close. Based on the above guidance, the CWP control switch was green flagged and permission was granted by operations to mechanical maintenance to begin manway gasket replacement.

The manway cover bolts were removed and the mechanical maintenance foreman and a mechanic attempted to remove the manway cover. When the pressure seal was broken, the mechanic allowed his right index finger to come between the cover and the waterbox. A negative pressure developed and sucked the cover back onto the waterbox and severed part of the mechanics finger. The mechanic and his severed part of the finger were then removed from the scene and transported to a local hospital. Attempts to reattach the severed part of the finger were unsuccessful.

A subsequent review of the control wiring diagrams for the vacuum breaker found that the CWP breaker control fuses had to be removed to open the vacuum breakers. A review of the event by the licensee found that:

- Neither the maintenance workers or the operator anticipated that a vacuum would exist after the manway cover was removed.

- The steps in the procedure for CWP operation led the ANPS to believe that when the CWP control switch was green flagged, no other precautions were required.

- The maintenance workers took no added precautions related to work with vacuum conditions.

- The work activity should not have been attempted without a clearance.

A review of this event and requirements by the inspector found that OP 0010122, Rev 58, "In-Plant Equipment Clearance Orders," Step 4.1, stated that a clearance would be required when operation of equipment could create a hazard to personnel or equipment. This failure to obtain a clearance is a violation, VIO 335/95-18-02, "Failure to follow clearance procedures."

2) SG Blowdown System Misalignment.

On September 9, while in the process of heating up in preparation for entry into Mode 3, the chemistry department requested that operations place the SGBD system in service to improve secondary chemistry. The ANPS directed the RCO to perform this task. At that time, several other evolutions were in progress. Approximately two hours later, the ANPS questioned the RCO on the progress of placing the SGBD in service. The RCO showed the ANPS the page of the procedure he was using to place the system in operation. The ANPS discovered that the RCO was using the SG Cooling and Wet Lay-Up Procedure, OP 1-0120027, which was the incorrect procedure for aligning the SGBD system. The ANPS informed the RCO that he was using the incorrect procedure and directed him to use the Blowdown System Operation Procedure OP, 1-00830020.

The RCO was relieved approximately 30 minutes later. He notified the oncoming RCO that the SGBD system was ready to be placed in service. The new RCO on shift, with the assistance of another RCO and a SNPO continued with the task of placing the SGBD system in service. The RCOs were in the control room and the SNPO was located at the closed cycle blowdown heat exchangers. In the control room, one RCO was controlling AFW to the SGs while the second RCO was adjusting SGBD flow. They were in radio contact with the SNPO at the SGBD heat exchanger who would adjust flow through the heat exchanger as needed. The control room experienced problems in balancing AFW flow, SGBD flow, and SG water level. The SNPO called the control room and informed them that steam was blowing out of a line in the vicinity of the closed cycle blowdown heat exchanger. The RCO isolated the SGBD and SG water level returned to normal.

An investigation by the licensee revealed that the initial system lineup using the incorrect procedure, OP 1-0120027, had opened a valve to the SGBD tank. When the RCO was found to be using the incorrect procedure, he did not correctly back out of the incorrect procedure. This left valves in the open position. These valves should have been closed prior to implementing the blowdown procedure OP 1-00830020.

A review of licensee's procedure by the inspector found that they did not provide explicit guidance to direct operators on how to back out of an incorrect procedure or a procedure that does not work and/or produce acceptable results. This topic is covered in general terms in operator training programs and it has been a general expectation that operators would take this action. The licensee is currently reviewing this item to determine if additional guidance is needed. This item is considered a weakness.

3) Unit 1 Pressurizer Safety Valves

At the end of IR 95-15, Unit 1 was in Mode 5, replacing the flange gaskets on the pressurizer safety valves and performing other various maintenance activities. After the gaskets were replaced, the RCS was filled and vented but unit startup was delayed while repairs were accomplished on EDG 1A/1B. The unit achieved Mode 4 on September 24 and Mode 3 on September 25. On September 26, simmering was identified on the pressurizer safety valves. The plant has a history of simmering/leaking safety valves and had modified their RCS pressurization procedure to require slow pressurization to permit the valves to soak, equalize valve component temperatures, and achieve better valve disc to seat contact. As RCS pressure was increased, the leakage also increased. After reaching NOP/NOT, the leakage on V1201 increased to about 1 gpm on September 27. RCS pressure was decreased to 2000 psi and the leakage decreased. The licensee evaluated this problem and decided to simultaneously pursue three parallel options:

a) Cool down, depressurize RCS, perform repairs/adjustments on SRVs, and adjust pipe hangers to reduce tailpipe loading on the SRVs.

b) Develop a design and obtain necessary parts to eliminate SRV tailpipes.

c) Perform engineering analysis and obtain NRC approval to operate with RCS at a reduced pressure.

The licensee started engineering work on options A and B while the unit was being cooled down and depressurized. During the plant cooldown an engineering evaluation and measurements were performed on the existing SRV tailpipe loading. It was found that one rigid hanger was exerting a significant amount of force on the tailpipe. After taking hot and cold strain gage measurements, engineering concluded that adjustments could be made to reduce the tailpipe stress. A decision was then made to place the other option on hold and proceed with this approach.

All installed safety valves were removed and sent to Wylie for repairs, adjustments and testing. The valves were returned from Wylie and installed on the pressurizer during the week of October 2. The Unit was then slowly brought up in temperature and pressure with specific hold and soak points to allow for temperatures of the valves and piping to reach equilibrium. This process was allowed to continue over several days until the system reached 2230 psia. This condition was achieved without any valve leakage. An engineering analyses, JPN-PSL-SENP-95-025, was then approved by the FRG to permit unit startup and operation at 2230 psia. This analyses concluded that operating at RCS down to 2225 psia was acceptable and did not require changes to Technical Specifications, the FSAR or plant procedures and also did not require a 10 CFR 50.59 evaluation for NRC approval. The inspector followed the plant pressurization, reviewed the licensee's analyses and agreed with their conclusions and corrective actions taken on this item.

The Unit was restarted on October 12 and went on-line on October 13, concluding a 73 day outage. No safety valve leakage was observed during the plant restart and none has been detected since restart.

The licensee had ordered new forged safety valves of a more rigid and sturdier design. The safety valves replacements for each unit is currently planned for the 1997 RFO on Unit 2 and the next RFO on Unit 1. The licensee believes that this will provide a permanent fix for this long term problem.

4) 1B EDG Failure

During a weekly surveillance run, the 1B EDG 12 cylinder engine developed a fuel oil leak at a piping connection in the FO return line to the diesel fuel oil day tank. The operator rapidly shut down the EDG to reduce fuel oil spray. The engine was declared out of service and a section of the piping was replaced. The EDG was satisfactorily retested and returned to service on October 8. Engineering laboratory analysis of the failed piping by the licensee determined that the failure was the result of high cycle fatigue. This crack evolved over a long period of time. The licensee also found that the piping configuration on the remaining engines was of a different design configuration and that the failure that occurred on 1B EDG was not applicable to the other EDGs.

The inspector did a walkdown inspection of the failure when it occurred. He also did a walkdown of the repairs after they were completed and verified that a PMT was conducted by a CR log review. He inspected the FO piping system on the remaining EDGs, discussed the failure and repairs in detail with the system engineer, and observed the engine in operation during a succeeding week's surveillance. Overall, this repair was handled in a timely and effective manner.

5) Unit 1 Restart.

The Unit 1 reactor was restarted on October 12 after a 73 day outage. The inspector reviewed the control room logs including the OOS, J/LL, Deficiency Log, and the OWA log prior to Unit restart. No deficiencies that would affect the unit's safe return to power were identified. The inspector conducted a plant walkdown and verified safety system alignments and

availability. Discussions were also held with plant management and on-shift operations personnel to verify that no deficiencies existed which could impact a safe unit restart.

The inspector observed restart activities over a period of several hours from the control room. Several delays, due to CEA problems, resulted in delaying reactor startup. Two CEA timing modules were replaced and reactor startup proceeded in an orderly and controlled fashion. The reactor entered Mode 2 at 12:03 and achieved criticality at 12:55. Maintenance work on a hydrogen seal oil pump and secondary chemistry cleanup delayed restart of the secondary plant until October 13. The turbine was placed on line at 3:00 p.m. on October 13, 1995.

The overall startup went well. It was well controlled and methodical with adequate management and supervisory oversight. Some Refueling outage activities were delayed on Unit 2 since priority was placed on Unit 1 restart.

6) Unit 2 RFO

a) Unit Shutdown/Cooldown

Unit 2 was shutdown on October 9, and entered a planned refueling outage of 49 days. ESF Safeguards Testing (paragraph 4.b.) was conducted during initial plant shutdown.

A reactor containment building and system walkdown by the licensee at operating temperature and pressure found boric acid buildup around a third of the circumference of a RCS B hotleg nozzle for a Steam Generator differential pressure detector. No active leakage was observed but the boron buildup indicated past leakage. Isotopic analysis of the nozzle boron residue revealed Cobalt-60 and an absence of Cobalt-58. This indicated that no recent leakage had occurred. Since the unit was already shut down and preparing to enter a refueling outage, the TS required shutdown was not applicable.

Engineering analyses of this item determined that the leakage resulted from PWSCC of the Alloy 600 material used in these nozzles. This is a well known industry problem. Units 1 and 2 have several nozzles that are susceptible to this problem. These include: pressurizer nozzles, RCS hot and cold leg instrument nozzles, pressurizer heater sleeves, SG leakoff and CEDMs.

The pressurizer steam space nozzles were replaced on Unit 2 during the last refueling outage and the 3 pressurizer water space nozzles are scheduled for replacement during the current outage. Based on the identification of this problem, the licensee procured the services and materials needed to also replace the 9 RCS Hot Leg Nozzles during the current Unit 2 outage. This work after integration into the outage schedule appeared to have minimal impact on the planned outage duration.

After discovery of the above, ESF Safeguards testing continued until a design problem (paragraph 4.b.) resulted in delaying test completion until later in the outage. The unit was then cooled down without any significant problem and entered mode 6 on October 18. Overall, the unit shutdown and cooldown was handled well. It was noted that since operations had gone to verbatim procedural compliance, a large number of the procedures used during plant shutdown and cooldown required temporary procedure changes.

b) RPV Disassembly and Defueling

Unit 2 was cooled down to 200° F on October 11 and work was started on removal of support components to permit reactor disassembly. The reactor vessel head was detensioned on October 19. CEA's were unlatched on October 20, the UGS was lifted on October 21 and core offload commenced on October 22. All of the above evolutions went well without any significant problems. During flooding of the lower refueling cavity on October 17, routine job distractions and inattention to this activity resulted in overfilling the lower cavity into the upper refueling cavity. This resulted in leaking approximately 100 gallons of water into the containment sump. A TC/PCR to OP 2-1600024 was developed and implemented to require that an operator be stationed in containment to follow this evolution in the future. The inspector followed all the above evolutions and conducted inspections as a part of routine daily plant tours.

Core offload initially incurred problems with the adjustment and calibration of the refueling machine load cell. The load cell was replaced October 23 and offload continued without any significant equipment problems and was completed on October 24. The inspector observed the offload activities from the control room, containment and the refueling machine. The activity met the TS required staffing. Overall the offload went exceptionally well. The inspector was impressed with the strict procedural compliance and good repeat back communications used during this evolution. The licensee practice of having contract equipment specialists available to provide for assistance on equipment repairs appeared to assist on rapid

resolution of the minor equipment problems encountered. No deficiencies were identified.

c. Plant Housekeeping (71707)

Storage of material and components, and cleanliness conditions of various areas throughout the facility were observed to determine whether safety and/or fire hazards existed. Overall plant cleanliness and equipment storage was deemed satisfactory.

No violations or deviations were identified.

d. Clearances (71707)

During this inspection period, the inspectors reviewed the following tagouts (clearances):

- 1-95-10-047 - This tagout isolated FCV-25-2 isolation valve (penetration P-11) for H&V Containment Purge Supply. The inspector verified that the 4 tags associated with this clearance were on the correct components, in the specified position/condition and that applicable OOS Log entry was made.
- 2-95-10-228 - This tagout isolated SB14530/SB14528. The inspector reviewed the Clearance Order only and noted that the 2 CCW drain valves, V14173 and V14455, on lines 58 and 59 were positioned Open at 0550 hours on October 23 and not initialed by the positioner. However, an Independent Verification was completed on these 2 valves. This discrepancy was brought to the attention of the work clearance center SRO for correction.
- 2-95-10-245 - This tagout was issued for configuration control. The inspector verified that both valves were in the closed position and properly tagged and that the applicable OOS Log entry was made.
- 2-95-10-246 - This tagout secured HVA/ACC-3A Air Handling Unit for the Unit 2 Control Room Air Supply due to the CCW OOS. The inspector verified that the breaker was off and properly tagged and that the applicable OOS Log entry was made.

No other deficiencies were identified.

e. Technical Specification Compliance (71707)

Licensee compliance with selected TS LCOs was verified. This included the review of selected surveillance test results. These verifications were accomplished by direct observation of monitoring instrumentation, valve positions, and switch positions, and by review of completed logs and records. Instrumentation and recorder traces were observed for abnormalities. The licensee's compliance with LCO action statements was reviewed on selected occurrences as

they happened. The inspectors verified that related plant procedures in use were adequate, complete, and included the most recent revisions.

f. Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems (40500)

1) Facility Review Group Meetings

The inspector attended the FRG meeting on October 10 where a proposed license amendment to permit operation with a pressurizer pressure minimum limit of 2115 PSI if needed due to leaking safety valves was reviewed. This amendment was supported by engineering evaluation JPN-PSL-SEFJ-95-039, Rev 1. After a presentation by engineering on this item, several questions were raised by operations. All questions were satisfactorily answered. The licensee intends to submit this request for NRR review if equipment fixes do not resolve the leaking pressurizer safety valves.

This FRG meeting was the first meeting the inspector had attended since the licensee revised the FRG Procedure ADM-0010520, Rev 29, in September and the Preparation, Revision, Revision/Approval of Procedure QI 5-PR/PSL-1 Rev 64 in October to use a subcommittee review of minor procedural changes. In conjunction with the above changes, the PGM has delegated the Chairmanship of the FRG to the Manager of Licensing or other designated managers as needed. The above meeting was chaired by the Manager of Licensing. The meeting had the required quorum and business was conducted in accordance with the above procedures, and the meeting issues were covered well.

The inspector discussed the changes that have occurred in FRG Chairmanship with the PGM. The PGM has indicated that he will approve all FRG actions and will periodically chair these meetings and will actually participate in FRG issues with major safety significance. This appears to be appropriate.

2) Licensee Self Assessment

a) The inspector reviewed QA Audit Report QSL-OPS-95-19, Training and Qualification Functional Area Audit and QSL-OPS-95-17 QA Performance Monitoring Audit reports for the months of August and September 1995. The Training and Qualification Audit appeared to be adequately detailed and contained one finding involving the retention of training records in the QA vault. Action is being taken to address this item.

QA Performance Monitoring was conducted on the following items: RCP 1A1 and 1A2 seal replacements, HVE-21A fan motor replacement, Local Leak Rate Testing on the RCB

Maintenance and Equipment and Personnel Air Locks, Unit 1 PORV repairs and testing, Health Physics activities during the PSL-1 Short Notice Outage, Operation of the new vehicle barrier gates, freeze seal activities and the closure and statusing of STARs required for a mode change. Two findings were identified in this report; one identified problems associated with the status of STARs prior to mode change and the second item found that a work activity was started by Construction Services prior to obtaining formal approval of the Nuclear Plant Supervisor. It was noted that STARs were written on each identified deficiency. Overall the monitoring activities appeared to be adequately detailed and focused on safety significant activities. The result of the inspections were well documented and provided good recommendations for improvement.

b) The inspector met with Quality Assurance on October 19, for a quarterly update. Items covered in this meeting included:

- Planned organizational staffing and responsibility changes
- Summary of recent audits and inspections
- Planned 4th quarter and plant outage inspection plans
- Increased operations oversight
- New controls for contractor work
- Recent independent technical reviews
- NPWO reviews
- Engineering and vendor audit results
- Nuclear fuels QA

Presentations were provided by group supervisors for each of the above items/area. The meeting provided the inspector with a good understanding of current QA and QC issues from the licensee's perspective. The inspector found the presentations were beneficial and the discussions open and frank. The licensee appears to be aware and taking appropriate corrective actions of deficiencies that were discussed.

4. Maintenance and Surveillance

a. Maintenance Observations (62703)

Station maintenance activities involving selected safety-related systems and components were observed/reviewed to ascertain that they were conducted in accordance with requirements. The following items were considered during this review: LCOs were met; activities were accomplished using approved procedures; functional tests and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; and radiological controls were implemented as required. Work requests were reviewed to determine the status of outstanding jobs and to ensure that priority was assigned to safety-related equipment. Portions of the following maintenance activities were observed:

1) Maintenance Rework during Short Notice Outage.

In IR 95-15, the inspector identified that several of the components that required work during the SNO had also been worked on during the previous Unit 1 refueling outage that ended in December 1994. The inspector questioned the licensee on this item and they agreed to review the issue. The licensee's review found that 1,029 total components were worked in the Unit 1 1994 RFO. Sixty-four of these same items were also worked on during this SNO. The licensee classified 32 of these as definite rework. The other items were classified as long standing known problems that frequently require maintenance and the remainder were considered as possible rework. Maintenance issued a STAR on each rework item to identify root cause and needed corrective action. The inspector noted that the number of items worked on in this refueling and SNO was 6.2 percent. It was also noted that several of the items had a history of repetitive maintenance and that some of these maintenance items were major contributors to this extension of the SNO.

2) Unit 1 EDG Load Oscillations.

In late August, the inspector questioned an entry in the Unit 1 control room log which identified a load oscillation during the monthly surveillance, 1-2200050B, on EDG 1B. Since there was no additional entries involving this item and any effect on component operability, the inspector discussed it with the DG system engineer. The SE stated that the oscillation resulted from MVAR swings on the grid.

On September 5, during the post maintenance and surveillance run on EDG 1B, some load oscillations were again observed and logged. Some adjustments were made in the governor control

circuitry and the swings were again credited to grid oscillations. On September 6, during a surveillance run of EDG 1A, the governor response was identified as being slow and non linear when load adjustments were made by the operator. Electrical maintenance, under the direction of the SE again made adjustments in the governor control circuitry. During a followup test, 500 to 1000 KW load swings occurred and a ground was found in the wiring harness between the DG control cubicle and the governor on EDG 1A2. PWO 95026057-02 and 95024478-01 were issued and repairs were made to the control wiring.

As a result of the above problems and to place more experience on the EDGs, the licensee assigned a new system engineer with extensive past EDG experience on the Unit 1 and Unit 2 EDGs.

On September 8, during surveillance testing, KW oscillation was again noted on EDG A and additional adjustments and tuning took place on the governor control circuits.

On September 20, EDG 1B experienced 400 KW load spikes during a surveillance run. During the troubleshooting effort a ground alarm started coming in each time the governor speed controls were manipulated. Troubleshooting located and repaired frayed wiring in the wiring harness between the local control panel and the governor. This was the same wiring where a problem had been identified and repaired on EDG 1A on September 6. The repairs were performed under PWO 95026002-1A.

The above repair on both engines was accomplished on back shift. The inspector retrieved and reviewed the PWO documentation and found that the repair was made using Raychem under an approved engineering repair method for damaged cable insulation 600 volt and below. The details for this repair were contained on drawing 8770-B-328, Sheet 19H for PCM 336-192. The inspector reviewed the PWOs and discussed the repairs with maintenance, engineering, and the system engineer. Based on this information and a successful post maintenance test, the repairs were deemed to be acceptable.

An engineering assessment of the above DC ground was that the plant DC System is designed as a floating, ungrounded system and a single ground on either the positive or negative bus would not affect operability of the bus or the EDG governor system. The inspector reviewed this issue and the governor control wiring circuit with the frayed wires with the system engineer and agreed with that conclusion.

On September 21, EDG 1B again experienced load oscillations during a surveillance test. This occurred when the operator attempted to make load adjustments. On September 22, VAR and KW swings again occurred on EDG 1A. EDG 1A was declared OOS by operations and a meeting was held with Operations, Engineering, System Engineering, and Plant Management to discuss this issue and overall EDG performance and reliability. As a result of this meeting an EDG maintenance vendor and governor manufacturer services were obtained to analyze and propose short term and long term corrective actions on these units. The short term corrective action resulted in initiation of PWOs 65-1328 on EDG 1B and 65-1326 on EDG 1A. These PWOs led to the replacement of the motor operated potentiometer, the speed load sensor, and amplifier modules on EDG 1A and the motor operated potentiometer and speed sensor module on EDG 1B. The electronic control units were readjusted and tuned in accordance with the vendor technical manual and with direct assistance provided by the governor and engine vendor representatives. The DGs were taken out of service one at a time and worked under LCO controls. Repairs were complete on September 24. Post maintenance testing on both units demonstrated considerably improved operator control during load changes. It was also noted that the frequency and magnitude of previously identified oscillations had decreased.

The inspector observed several of the above EDG runs and attended the meeting held on these issues. He also had frequent interface with the system engineer, maintenance and vendor personnel who worked on the EDGs.

The licensee decided to place the Unit 1 EDGs on an increased surveillance of every seven days until they gained confidence that the above repairs had addressed the previous problems. The system engineer and maintenance management have stated that they are reviewing the overall maintenance program on the EDG. They have asked for inputs from the engine and governor vendors and intend to upgrade the overall maintenance of these vital components. They have also stated that they are considering upgrading the governor control system to a newer model that has improved reliability and more readily available spare parts.

The licensee's efforts on the EDGs have resulted in improved performance. However, it was noted that this did not occur until after several failures and significant questioning by the NRC. This item is identified as a weakness in diesel generator maintenance and the lack of adequate equipment performance standards by operations.

3) (Closed) URI 389/95-05-03, "Incore Instrument Wiring Errors"

IR 95-05 documented apparent wiring discrepancies in Unit 2 ICIs. The discrepancies were associated with ICI flange 8 and resulted in erroneous ICI spatial input to the plant computer. During the current Unit 2 outage, the licensee performed an inspection of ICI flange 8 wiring prior to de-terminating the wiring for vessel head removal.

The subject inspection was performed under PWO 64/4529 and included checks of wiring from the refueling disconnect panel to the top of the reactor head. The licensee found that 4 of 6 ICI strings were improperly wired. The results were recorded for inclusion in detector burnup calculations.

As stated in IR 95-05, I&C Procedure 1400023, "Incore Instrumentation (ICI) Outage Tasks," Appendix K, "ICI Flange Assembly," required two separate reverifications of proper wiring once flange connections were made. The failure of the licensee to perform adequate verifications of the wiring of ICI flange 8 following reconnection during the 1994 Unit 2 refueling outage constitutes a violation. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy, and will be identified as NCV 389/95-18-04, "Inadequate Verification of ICI Wiring Connections After Reassembly."

b. Surveillance Observations (61726)

Various plant operations were verified to comply with selected TS requirements. Typical of these were confirmation of TS compliance for reactor coolant chemistry, RWT conditions, containment pressure, control room ventilation, and AC and DC electrical sources. The inspectors verified that testing was performed in accordance with adequate procedures, test instrumentation was calibrated, LCOs were met, removal and restoration of the affected components were accomplished properly, test results met requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel. The following surveillance test(s) were observed:

1) OP 1-2200050A, 1A EDG Periodic Test

On October 5, the inspector observed the licensee perform the monthly surveillance on the "1A" EDG using OP No. 1-2200050A, Rev 22. A local start was performed per step 8.1.18 of the procedure. After performing the normal engine checks at 375 to 475 RPM (idle), the operator placed the Idle Start Mode Selector Switch in AUTO and verified that the diesel increased speed to 900 RPM. At this time, the Local and RTGB STOP/AUTO/START Switch were to have both the green and red lights illuminated per the <u>NOTE</u> in the procedure. The operator at the local station notified the control room that the red light was not illuminated. The System Engineer, who was present for the test, issued a PWO identifier tag #72844 for a faulty lamp socket. Several indicator lamps on this local panel had been worked and closed out on September 25 under a minor PWO (Work Request #95015426 identified intermittent amber lights). The inspector's followup with the Electrical Planning

Department showed that the bulbs had been replaced). The System Engineer released the diesel for test and initiated Work Request #95016229 to correct the faulty lamp socket. The diesel was loaded to approximately 3500 KW for its 1 hour run. The inspector reviewed the strip chart for load and saw no fluctuations or spiking. Following successful completion of the surveillance the EDG was returned to it's standby status.

2) OP 2-0400050 Periodic Test of the Engineered Safety Features

Background

Engineered Safety Features (ESF) are designed to mitigate the consequences of postulated DBA. The ESF function is to limit, contain, control and terminate an accidental release of radioactive fission products, particularly as a result of accidents that could release large amounts of energy within the containment structure. ESF systems keep exposure levels to the public and plant personnel below applicable limits.

St. Lucie Unit 2 utilizes the following ESF systems:

1. Containment Structure
2. Containment Spray System
3. Containment Cooling System
4. Shield Building Ventilation System
5. Containment Isolation System
6. Combustible Gas Control System
7. Safety Injection System

Unit 2 Technical Specifications identify the LCOs and associated surveillance requirements. The surveillance requirements specify tests and the frequency requirements to demonstrate operability of systems important to safety. Operating Procedure No. 2-0400050, Rev 16, "Periodic Test of the Engineered Safety Features," satisfies a large number of ESF surveillance requirements. This OP verifies ESF system actuations with plant systems configured as closely as possible to those found in the normal operating procedures.

The OP is organized into 12 blocks of test instructions and 15 Appendices. Multiple TS requirements are verified by this test procedure.

The NRC inspector selected this OP for observation due to the first use on Unit 2 following procedural revision. Past surveillance problems included:

- IR 92-14 identified a procedural violation for the Failure to Adequately Test the C Intake Cooling Water Pump. This was based on a failure to test the trip and restart of the

C ICW Pump on the energized emergency bus following a LOOP.

- IR 94-12 identified a violation for inadequate corrective actions involving the surveillance testing of the C ICW Pump. This involved a failure to verify C train ICW and CCW pump load shed and sequencing functions when powered from their alternate power supply busses.

- IR 94-22 identified a violation involving inadequate corrective action to a NRC violation regarding EDG operability. This violation identified an electrical alignment of the 1C ICW pump to the 1A3 bus while relying on operability of the 1A EDG. Load shed testing of the 1C ICW Pump, when aligned to this bus, had not been performed as required by TS for EDG operability.

Test Observation

On October 12, the inspector attended the pretest briefing conducted by the operations manager and found it to be thorough and detailed. All test personnel were verified in attendance. Items covered included:

- Precautions and Limitations
- Past experiences and lessons learned
- Procedural control
- Use of effective communications
- Contingencies and test termination criteria\

It was also stressed that the operating crew retained responsibility for safe plant operation.

On October 12, the inspector observed the performance of the following test procedure steps:

Step 8.4

- Verifies initial system alignments
- Secures SDC and realigns SDC system, ESFAS logic and ICW system for test
- Initiates a LOOP by simultaneously opening the Startup Transformer feeds to the 4.16 KV buses 2A2 and 2B2
- Simultaneously initiates a SIAS, CIAS, MSIS and CSAS using the trip test pushbuttons
- Verifies proper system response
- Resets and restores systems to pretest alignments

During the realignment of the ICW system for test, the manually operated ICW pump discharge valves were throttled to 10 turns open from their normally full open position. This was done to minimize potential equipment damage due to water hammer when starting the ICW pumps under no flow conditions. The ANPO assigned to this test area looked ahead in the procedure and requested permission to throttle the 2C ICW Pump discharge valve before SDC was secured. This was proposed to minimize the time required to realign the ICW system after SDC was secured. The Test Director agreed since the 2C ICW would be in a P-T-L position for the test. The ANPO reported that the valve locking device (a padlocked chain) could not be removed and that he was unable to insert the key into the padlock due to corrosion. After removing the chain with boltcutters, the ANPO was unable to reposition the valve without excessive force, i.e. the operator appeared to be frozen. The Test Director determined that leaving this valve in the full open position would not impact the test or create a potential for equipment damage. As followup to this problem, however, the Test Director briefed other test personnel that if a similar problem was encountered in repositioning the 2A or 2B ICW discharge valves, SDC would be restored and the test temporarily secured. The inspector was impressed by the ANPO's initiative in looking ahead in the procedure and identifying this impediment to testing. This problem recognition and resolution minimized the period of time that SDC was secured and which could have interrupted the test.

Shutdown cooling was secured at 2:26 p.m. and the final system realignments performed. RCS temperature was 120° F. At 2:40 p.m., the LOOP was initiated by simultaneously opening the Startup Transformer feeds to the 4.16 KV buses 2A2 and 2B2. One second later the SIAS, CIAS, MSIS and CSAS trip test pushbuttons were depressed inserting the ESFAS Signals. All ESFAS actuations occurred as expected. SDC was restored at 1505 hours. During the 39 minutes SDC was secured the STA calculated that the HUR was approximately 66° F, however RCS temperature increased to only 160° F due to partial core cooling from the operating ECCS pumps.

An unexpected EDG 2B Local Alarm (A-26 annunciator) was received when the LOOP was initiated. This was caused by the failure of the EDG 2B electrical fuel pump. The attached fuel pump allowed for continued operation. This alarm later cleared and a PWO was written to correct this problem. Also, test personnel reported problems with the EDG 2A test recorder. A cross-check with installed instrumentation locally and in the control room as well as a hand held calibrated voltmeter, isolated the problem to an apparent drift of the null point (bias) on the test recorder channels selected.

At 3:42 p.m., a loud noise was heard from the H&V room adjacent to the control room. The operating HVAC/ACC 3-A was secured and the noise stopped. The licensee suspected a freon release caused by inadequate ICW flow to the CCW Heat Exchangers.

HVAC/ACC 3-B was placed in service, however, a failure alarm was received on that train also. This placed Unit 2 in AS b. of TS 3.7.7 which with both control room emergency air cleanup systems inoperable, required the suspension of all operations involving core alterations or positive reactivity changes. The access door from the control room to the H&V room was blocked with explicit instructions given by the Operations Manager to the NPS that entry for safety and maintenance personnel would be through the access door inside the RCA and not the control room. This would ensure continued control room habitability. A technician from the safety department reported to the control room, and due to poor communications, entered the H&V room through the blocked access door. The technician entered the H&V room alone using a handheld oxygen meter sampling at neck level. The Operations Manager ordered the technician out the H&V room and posted a sign on the access door stating, "No entrance without prior NPS approval". A followup survey of the H&V atmosphere using a freon detector confirmed that freon levels were within an acceptable range. Maintenance reported that the 3-C freon safety valve had apparently lifted based on low system pressure and that both the 3-A and 3-B units were available. Unit 2 then exited TS 3.7.7. A followup discussion by the inspector with the Operations Manager confirmed that the safety department technician's actions were inconsistent with plant procedures and that the technician had been counseled on this item. The licensee is evaluating a procedural enhancement which will either fully open the ICW discharge valves when flow is reestablished during the test or increase the number of turns throttled open to preclude recurrence of this problem.

A list of equipment problems identified during steps 8.1 through 8.4 and their associated PWOs, where applicable, include:

a. HCV-09-1A, A MFW isolation valve, valve was slow to open, PWO 5424/64

b. MV-09-10, 2C AFW Pump discharge, Unable to throttle, PWO 1451/66

c. V09136, 2B AFW Pump Supply isolation valve, Valve leaking by, PWO 5072/62

d. V09158, 2C AFW Pump Supply isolation valve to SG 2B FW inlet, Valve leaking by, PWO 5092/66

e. MV-09-13, Cross-tie between AFW pump 2A and 2B discharge, Valve leaking by, PWO 5074/62

f. MV-09-14, Cross-tie between AFW pump 2A and 2B discharge, Valve leaking by, PWO 5075/62

g. FCV-25-35, Shield building vent & purge control to vent stack, OL would not reset, PWO 1458/62

h. 2B2 EDG, DC FO Pump binding, PWO 5098/62

i. SUPS, SUPS lost in LOOP test, PWO 1447/66

j. HVE-6A, The overload tripped when the A train Shield Building Ventilation Fan was stopped and then restarted. This was due to a high rad signal being present when the radiation monitor lost power during the LOOP. This signal was reset and the overload for HVE-6A was also reset. HVE-6A was OP tested SAT.

k. 2A2 RCP OIL LIFT PUMP, This pump restarted when the SIAS signal was reset. The licensee will review the applicable CWDs and determine if a PWO is required.

l. RM-23's, Approximately 1/2 of the RM-23 monitors were lost during the LOOP. The licensee generated a STAR to address this problem.

m. FCV-25-32/33, HVE-6A/6B inlet control valves, These two valves closed upon reset of the CIAS signal. This was due to the high rad signal being present when the radiation monitor lost power during the LOOP. When the signal was reset, the valves functioned normally.

Items j. and m. above will be incorporated as a procedural enhancement to recognize the failed high rad monitor signal during the LOOP.

Step 8.5

- Aligns the 2AB bus to the A Electrical Side
- Initiates a load rejection with a concurrent LOOP/Swing Pump SIAS Signal using a Group 9A SIAS Signal
- Realigns the 2AB bus to the B Electrical Side
- Initiates a load rejection with a concurrent LOOP/Swing Pump SIAS Signal using a Group 9B SIAS Signal

Testing of the A Electrical Side was satisfactorily completed prior to shift turnover. When testing resumed on the B Electrical Side, the 2C Charging Pump failed to start when the Group 9B SIAS Signal was inserted. This was due to a procedural deficiency, i.e., channel MB Containment Pressure SIAS 127, BA 101, 301 bypass key was in the bypass position. The test was exited prior to completing step 8.5 and resumed at step 8.6.

Step 8.6

- Aligns both 2A and 2B EDGs with offsite power at or near full load
- Initiates a Channel A CIAS then resets
- Initiates a Channel B CIAS then resets
- Initiates a Channel A SIAS then resets
- Initiates a Channel B SIAS then resets
- Initiates a Channel A CSAS then resets
- Initiates a Channel B CSAS then resets

After each ESFAS Channel is actuated individual component actuations are verified.

This particular step of the procedure had been revised. The previous procedure Revision inserted a SIAS Signal prior to the CIAS Signal. This did not allow for separate verification of the CIAS Signal actuations since the SIAS also generated a CIAS signal by design. The licensee believed that changing the order would enhance the procedure and provide more detailed ESFAS Signal verifications.

After the Channel A CIAS Signal was inserted and the component actuations verified, Channel A CIAS was reset. At this time the 2A EDG tripped on reverse power. The test was secured and the 2A EDG declared inoperable.

An investigation by the licensee determined that during the performance of Section 8.6 of OP 2-0400050, EDG 2A was running parallel to the grid and loaded to >3600 KW. CIAS-A was manually initiated in accordance with step 12 of the test procedure. Actuation of CIAS caused the EDG A governor circuit to change from the droop mode (i.e. follows the grid frequency) to an isochronous mode (i.e. reverts to preset frequency and does not follow the grid frequency). The EDG 2A preset frequency was lower than that of the grid. This resulted in reducing fuel to slow the EDG down, leading to reverse power flow causing the generator to act as a motor (or synchronous capacitor). The reverse power relay actuated; however, due to the presence of the CIAS-A signal, the relay trip function was blocked. Upon resetting of the CIAS-A signal, the reverse power relay trip block was removed and the EDG tripped. Total time of EDG operating under reverse power was approximately 45 seconds.

A review of the ERDADS printout of Bus 2A3 voltage and current and EDG current confirmed a sudden change at the approximate time CIAS was initiated. The current drawn by the EDG 2A generator during the reverse power incident was approximately 330 amps. From this the licensee determined that the 2A EDG output current of 477.54 amps reversed to 330.38 amps for a net change of 807.84 amps which was sufficient to actuate the reverse power relay. Concurrent with this, Bus 2A3 voltage changed from 4331.7 volts to 4360.2 as a result of the generator producing additional MVARs, i.e., acting as a synchronous capacitor with a high power factor. This value is well within the 660 amp continuous rated capacity of the generator windings. Based on the above, System and Component Engineering determined that EDG 2A had not been damaged by the incident. The 2A EDG voltage regulator was visually inspected with satisfactory results and the 2A EDG was started and loaded successfully as an operability check. Further, performance of the regular 18-month preventative maintenance (Maintenance Procedures 2-2200062 and 2-M-00180), included a thorough inspection on EDG 2A and did not identify any damage as a result of this event.

An engineering review of the EDG control circuits found that the EDG starts on SIAS, CSAS or CIAS and that these signals cause the EDG to change from droop mode to isochronous mode (Ref. CWDs 957 & 958 and Vendor Manual 2998-7434). Opening the Bus 2A2-2A3 tie breaker will also change the EDG from droop to isochronous modes. In the case of SIAS and CSAS (CSAS will only occur with SIAS), the EDG circuit breaker will trip if closed, permitting the EDG to run separate from the offsite power source. However, CIAS without SIAS does not trip the EDG breaker, resulting in the EDG operating in isochronous mode while still connected to offsite power. This condition is not expected during normal operation or any design basis event requiring the EDGs.

STAR #951391 was written to identify this design deficiency on the Unit 2 EDGs.

EDG 2B has not been tested with a manual CIAS actuation, therefore its operability was not affected.

The Unit 1 EDGs governor control design is different from the Unit 2 EDGs. The Unit 1 EDGs have been successfully tested using an essentially identical ESFAS test procedure. Therefore, there is no operability concern from the Unit 1 EDGs.

Based on the above, the EDGs were considered operable.

The inspector reviewed the above assessment and noted that while actuation of the CIAS relay without SIAS is not expected during normal operation, both Unit 2 EDGs are tested monthly and operated a minimum of 1 hour paralleled to the offsite power source. Actuation of CIAS under these test conditions could have resulted in damage to the EDG.

The inspector was concerned by several aspects related to the design deficiency identified during testing:

1. Integrated Safeguards testing over the past 2 years had received a high level of management and technical support attention due to the licensee's misinterpretation of testing requirements particularly related to swing bus components. The current test procedure revision changed the test sequence for initiating CIAS/SIAS/CSAS Signals in step 8.6 as a procedural enhancement. Although this same test was successfully performed earlier on Unit 1 and satisfactorily tested on the simulator, it was not reviewed in sufficient detail to assess the impact upon equipment or system operation on Unit 2.

2. This condition has existed since initial construction. There was no licensee identification of this failure mode, i.e. receiving a CIAS Signal while paralleled to an offsite power source.

3. The 2A EDG was operated for approximately 45 seconds with a reverse power trip blocked. A review of the CWDs determined that a local reverse power alarm occurred which the licensee believes also generated a control room alarm. Since operators were either unaware or did not question these alarms, the inspector concluded that it was doubtful whether operator actions would have prevented damage if the CIAS had not been reset unblocking the reverse power trip.

The licensee has placed a temporary hold on 2A/B EDG testing pending resolution of their STAR.

On October 23, the licensee issued JPN-PSL-SEES-95-034, Rev. 0 Safety Evaluation for the provisions to trip emergency diesel generator output breaker on CIAS in plant modes 5 and 6. This short term plant temporary modification (plant mode 5 and 6 only) involves wiring any convenient "deenergize to close" CIAS spare contact in the ESFAS cabinet (A or B, as required) to trip the EDG output breaker upon receiving an actual or spurious CIAS while operating the diesel generator paralleled to an offsite power source. The inspector reviewed the Safety Evaluation and found the approach acceptable and consistent with existing licensing requirements.

The above short term plant temporary modification was not implemented. Rev 1 to the above Engineering Report was issued on October 27. The licensee's long term corrective action involved deletion of the automatic EDG start on CIAS and CSAS since it removed the adverse conditions, was relatively easy to implement and test, and can be installed under 10CFR50.59. This modification will also be implemented on Unit 1 at the earliest convenience for consistency between units and to ensure that spurious signals would not bypass the non-safety trips if the EDG was connected to offsite power. The inspector reviewed and evaluated the revised Engineering Report and found it to be acceptable.

10 CFR 50 Appendix B Quality Assurance Criteria for Nuclear Power Plants and Fuel Processing Plants requires, in part:

a. that "Measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in § 50.2 and as specified in the license application, for those systems, structures and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions... The design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program." [CRITERION III, DESIGN CONTROL]

b. that "A test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed ..." [CRITERION XI]

The licensee's failure to identify this design deficiency during initial design and testing and adequately review the revised Safeguards Test procedure for performance on Unit 2 is considered a violation, VIO 389/95-18-03, "Failure to Adequately Design and Test the Emergency Diesel Generator 2 A/B Engineered Safety Feature Control Logic." This licensee identified and corrected violation was considered for treatment as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy. This violation is being cited due to the lack of questioning attitude and a weakness in the depth of review during the changing, updating, and correcting of the applicable EDG test procedure.

3) Missed CEA Position Surveillance

On October 20, the licensee identified that operations had missed the Unit 1 TS 4.1.3.3 surveillance which verifies CEA position indication difference between reed switch position transmitters and pulse counting channels to be less than 4.5 inches. TS requires this surveillance once every 12 hours and the licensee accomplishes this surveillance once each shift in accordance with AP 1-0010125, Rev 102, "Schedule of Periodic Test, Checks, and Calibrations," Check Sheet 1, step 16. This surveillance was missed on the day and peak shifts on October 19.

An investigation by the licensee found that the last surveillance was performed between Midnight and 2:00 AM on

October 19. The readings were recorded on the Control Room Log sheet for CEA positions. The operator also signed off completion of the surveillance on AP 1-0010125 Check Sheet 1. The midshift ANPS reviewed the log and check sheet, but inadvertently placed the CEA position log sheet in the licensing review file rather than returning it to the RCO. The oncoming RCO did not identify that the log sheet was missing and therefore he did not perform the surveillance. Since the RCOs were standing 12 hour shifts during the refueling of a unit, he was responsible for completing the day and peak shift surveillance. Prior to turnover to the next RCO, he signed off the AP 1-0010125 check sheet indicating that the CEA position indicator surveillance had been completed.

The next midshift ANPS, during his documentation review on October 20, discovered that the surveillance had been missed for the day and peak shift. The readings were then taken at approximately 1:00 AM on October 20. The total time between surveillances was approximately 24 hours which exceeded the allowable interval including a 25 percent extension period of 15 hours.

Since the pulse counting channels and CEA reed switch positions were both operable and alarms were available to indicate any significant CEA misalignment, this item had minimal safety significance.

It has been noted that the licensee's current practices permit operators to complete surveillances such as this and later sign off the check sheet near the end of their shift. Had the check sheet been required to be signed off when the surveillance was actually done vice the end of the shift, then this event would not have occurred.

This licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy, and will be identified as NCV 335/95-18-05, "Missed Surveillance on CEA Position Indication."

4) Missed Surveillance on RCS Born Sample

Unit 2 Technical Specification 3.1.2.9 requires that boron concentration shall be verified consistent with Shutdown Margin in Mode 6 by sampling the RCS at a frequency determined by the number of operable charging pumps. The AS requires that all operations involving core alterations or positive reactivity changes be suspended if the TS requirement is not met.

At approximately 6:00 AM on October 20 the Shift Technical Advisor identified that two charging pumps were operable and that the RCO was logging the Boronometer readings hourly to verify Born concentration. After review, it was determined that sampling vice using the boronometer was required and that with 2 charging pumps operable the sampling frequency was 95 minutes. Further review by the operators found that this TS had been met by using the boronometer since entering Mode 6 at 4:30 AM on October 18. During this time span Chemistry had been taking RCS samples every 72 hours as required by TS 4.1.9.2. Upon identification of this item the NPS directed that 2C Charging pump be disabled and Chemistry to begin taking samples every 220 minutes as required with 1 Charging pump available. During the above time span when samples were not taken, the boronometer readings showed that RCS boron concentration was consistent with the shutdown margin requirements, and no core alterations or positive reactivity changes had occurred. The inspector verified this action had been taken and the readings were current by log reviews.

The licensee's above corrective actions were adequate to prevent recurrence of the event. However, the inspector noted that the licensee's initial evaluation of the event found that the licensee's method of scheduling and tracking this surveillance, AP 2-0010125, Rev 55, "Schedule of Periodic Test, Checks and Calibration," check sheet 1 item 11 was poorly worded and possibly misleading to the operator. The inspector, on conducting an evaluation of the licensee action to correct this procedural deficiency, visited the control room on October 26 and found that a procedure TCN had not been issued to clear up the procedural questions and the operators on watch did not understand this problem and the correct TS interpretation or the operator actions that should be taken. Based on the above, the inspector met with the Operations Supervisor who stated that the task of correcting the procedure had been assigned to a night shift NPS. A procedure change was implemented on October 26, to address this issue. It was noted that since the boronometer was in service and used during this time span and since the correct boron concentration was maintained, this item has little safety significance. The licensee identified and corrected violation is being treated as a non-cited violation, consistent with Section VII of the NRC Enforcement Policy and will be identified as NCV 389/95-18-06, "Missed RCS Boron Concentration surveillance during Mode 6."

5. Engineering Support (37551)

a. Review of adequacy of Spent Fuel Pool Cooling Design assuming single failure.

The inspector reviewed the both unit's FSARs and spoke with Reactor Engineering regarding the Spent Fuel Pool Cooling Design issue addressed in the Region II Director of Reactor Projects memo to all Region II SRIs. This issue questioned:

1) Is the Spent Fuel Pool heat removal capability based on the assumption that only 1/3 of the core would be off-loaded, rather than the full core as has become the standard practice at some sites and,

2) Is the Spent Fuel Pool heat removal capability adequate in this case assuming single failure.

a) Unit 1 was designed to maintain a storage capacity of no more than 1706 fuel assemblies (7 2/3 cores of spent fuel assemblies, control element assemblies, new fuel during initial core loading and the spent fuel shipping cask).

Two thermal loading analyses have been performed; the Normal Batch Discharge and the Full Core Discharge. In the case of the Normal Batch Discharge, the analysis assumes that 18 batches of 80 assemblies each have been discharged from the core in 18 month intervals. A refueling batch of 80 assemblies was added 150 hours after reactor shutdown. This analysis showed a maximum pool bulk temperature of 133.3 degrees F with the fuel pool cooling system in service. For the Full Core Discharge, assuming that 73 of the assemblies have 90 days of irradiation, 72 have 21 months of irradiation and the remaining 72 assemblies have 39 months of irradiation (217 assemblies total), the analysis showed a maximum pool bulk temperature of 150.8 degrees with the fuel pool cooling system in service.

Unit 1 has 2 fuel pool cooling pumps supplying flow through a single spent fuel pool heat exchanger. The Unit 1 FSAR requires 2 fuel pool pumps and the heat exchanger in service for an abnormal, or full core offload. FSAR section 9.1.3.4.3 states "In the event of a complete loss of cooling capability, there is sufficient time to provide an alternate means of cooling". The inspector has requested a clarification of this section from the licensee.

There were currently 973 spent fuel assemblies and 16 miscellaneous assemblies in the Unit 1 Spent Fuel Pool. Existing space allows for operation until the year 2007.

b) Unit 2 was designed to maintain a storage capacity of no more than 1076 fuel assemblies (approximately 5 full cores and the fuel handling tools).

Two thermal loading analyses have been performed; the Normal and the Accident Case Assumptions. The Normal Case assumes;

1. 11 batches (each 1/3 core) discharged

2. Most recent batch cooling for five days after shutdown
3. Adiabatic heat up of the pool

The analysis showed a maximum pool bulk temperature of 131 degrees F with the fuel pool cooling system in service.

The Accident Case assumes;

1. 11 batches plus one full core discharged
2. One (1) core cools for 7 days
3. Most recent 1/3 core batch cools for 90 days

This analysis shows a maximum pool bulk temperature of 148 degrees F with the fuel pool cooling system in service.

Unit 2 has redundant trains of spent fuel pool pumps and heat exchangers. Under accident conditions, i.e. loss of 1 train, pool temperatures are expected to rise to approximately 155-160° F. This exceeds the SRP Subsection 9.1.3 recommendations, however, the licensee considers this to be acceptable.

There are currently 544 spent fuel assemblies, 84 new fuel assemblies and 5 miscellaneous assemblies in the Unit 2 Spent Fuel Pool. Existing space allows for operation until the year 2002.

6. Plant Support (71750)

a. Fire Protection

During the course of their normal tours, the inspectors routinely examined facets of the Fire Protection Program. The inspectors reviewed transient fire loads, flammable materials storage, housekeeping, control hazardous chemicals, ignition source/fire risk reduction efforts, fire protection training, fire protection system surveillance program, fire barriers, fire brigade qualifications, and QA reviews of the program. No deficiencies were identified.

b. Physical Protection

During this inspection, the inspector toured the protected area and noted that the perimeter fence was intact and not compromised by erosion or disrepair. The fence fabric was secured and barbed wire was angled as required by the licensee's Physical Security Plan (PSP). Isolation zones were maintained on both sides of the barrier and were free of objects which could shield or conceal an individual.

The inspector observed personnel and packages entering the protected area were searched either by special purpose detectors or by a physical patdown for firearms, explosives and contraband. The processing and escorting of visitors was observed. Vehicles were searched, escorted, and secured as described in the PSP. Lighting of the perimeter and of the protected area met the 0.2 foot-candle criteria.

In conclusion, selected functions and equipment of the security program were inspected and found to comply with the PSP requirements.

c. Radiological Protection Program

Radiation protection control activities were observed to verify that these activities were in conformance with the facility policies and procedures, and in compliance with regulatory requirements. These observations included:

- Entry to and exit from contaminated areas, including step-off pad conditions and disposal of contaminated clothing;
- Area postings and controls;
- Work activity within radiation, high radiation, and contaminated areas;
- Radiation Control Area (RCA) exiting practices; and,
- Proper wearing of personnel monitoring equipment, protective clothing, and respiratory equipment.

7. Other Areas

Susan Clark, Chairman of the Florida Public Service Commission visited the plant on September 22. She was provided an overview and tour of both units. The SRI attended a working lunch, question and answer session, with the Chairman and her staff assistant, Mr. W. Berg, and the licensee.

8. Exit Interview

The inspection scope and findings were summarized on November 1, 1995, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection results listed below. The licensee questioned violations 389/95-18-02, "Failure to Follow Clearance Procedures," and 389/95-18-03, "Failure to adequately Design and Test Emergency Diesel Generator 2A/B Engineered Safety Feature Control Logic." They stated that since the first item was identified and corrected by the licensee it should be a non-cited violation. The inspector acknowledged that the item could have been non-cited but since this item was one of the many examples of procedural noncompliance identified in the past several months, the licensee's corrective actions for these previous violations should have reinforced the need for procedural compliance and prevented this violation.

The second item involved the inadequate design of EDG 2 A/B ESF control logic, the licensee stated that this item was the result of an error in the initial design which had been detected by a recently improved integrated safeguards test procedure. Therefore, they felt that this item should also be non-cited. The inspector noted that even though it was an old design issue, the licensee, in the past 18 months had done extensive research into these design features while upgrading the ESF test procedure in response to two violations in this area. Since this afforded the licensee ample opportunity to identify this error, the NRC did not exercise discretion on this item. Proprietary material is not contained in this report.

Type	Item Number	Status	Description
VIO	50-335/95-18-01	Open	"Failure to Follow Procedures and Maintain Current and Valid Log Entries in the Rack Key Log and Valve Switch Deviation Log," paragraph 3.a.
VIO	50-335/95-18-02	Open	"Failure to follow clearance procedures," paragraph 3.c.
VIO	50-389/95-18-03	Open	"Failure to Adequately Design and Test the Emergency Diesel Generator 2 A/B Engineered Safety Feature Control Logic," paragraph 4.b.
NCV	50-389/95-18-04	Closed	"Inadequate Verification of ICI Wiring Connections After Reassembly," paragraph 4.a.
NCV	50-335/95-18-05	Closed	"Missed Surveillance on CEA Position Indication," paragraph 4.b.
NCV	50-389/95-18-06	Closed	"Missed RCS Boron Concentration surveillance during Mode 6," paragraph 4.b.
URI	50-389/95-05-03	Closed	"Incore Instrument Wiring Errors," paragraph 4.a.

9. Abbreviations, Acronyms, and Initialisms

AB	Auxiliary Building
ACC	Heating Ventilation and Air Conditioning
ADM	Administrative Procedure
AEOD	Analysis and Evaluation of Operational Data, Office for (NRC)
AFAS	Auxiliary Feedwater Actuation System

AFW	Auxiliary Feedwater (system)
ANPO	Auxiliary Nuclear Plant [unlicensed] Operator
ANPS	Assistant Nuclear Plant Supervisor
AP	Administrative Procedure
ATTN	Attention
cc	Cubic Centimeter
CCW	Component Cooling Water
CEA	Control Element Assembly
CEDM	Control Element Drive Mechanism
CFM	Cubic Feet per Minute
CFR	Code of Federal Regulations
CIAS	Containment Isolation Actuation Signal
CR	Control Room
CSAS	Containment Spray Actuation System
CW	Circulating Water
CWD	Control Wiring Diagram
CWP	Circulating Water Pump
DBA	Design Basis Accident
DG	Diesel Generator
dpm	Disintegration Per Minute
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EDO	Executive Director for Operations, Office of the (NRC)
ERDADS	Emergency Response Data Acquisition Display System
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Feature Actuation System
F	Fahrenheit
FCV	Flow Control Valve
FO	Fuel Oil
FPL	The Florida Power & Light Company
FR	Federal Regulation
FRG	Facility Review Group
FSAR	Final Safety Analysis Report
FW	Feedwater
gpm	Gallon(s) Per Minute (flow rate)
HCV	Hydraulic Control Valve
HEPA	High-Efficiency Particulate Air
HP	Health Physics
HPSI	High Pressure Safety Injection (system)
HRA	High Radiation Area
HUR	Heatup Rate
HVA	Heating Ventilation and Air Conditioning
HVAC	Heating Ventilation and Air Conditioning
HVE	Heating and Ventilating Exhaust (fan, system, etc.)
IAW	In Accordance With
ICI	Incore Instrument
ICW	Intake Cooling Water
IR	[NRC] Inspection Report
J/LL	Jumper/Lifted Lead
JPN	(Juno Beach) Nuclear Engineering
KW	KiloWatt(s)

LCO	TS Limiting Condition for Operation
LOOP	Loss of Offsite Power
LPSI	Low Pressure Safety Injection (system)
MFW	Main Feed Water
MSIS	Main Steam Isolation Signal
MV	Motorized Valve
MVAR	Reactive Load
MWe	Megawatt(s), Electrical [Energy from the Electrical Generator]
NCV	NonCited Violation (of NRC requirements)
No.	Number
NOP	Normal Operating Pressure
NOT	Normal Operating Temperature
NPF	Nuclear Production Facility (a type of operating license)
NPS	Nuclear Plant Supervisor
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NRR	NRC Office of Nuclear Reactor Regulation
NWE	Nuclear Watch Engineer
OL	Overload
ONOP	Off Normal Operating Procedure
OOS	Out Of Service
OP	Operating Procedure
OPS	Operations
OWA	Operator Work Around
PCM	PerCent Milli (0.00001)
PCR	Procedure Change Request
PDR	NRC Public Document Room
PGM	Plant General Manager
PMT	Post Maintenance Test
PORV	Power Operated Relief Valve
psi	Pounds Per Square Inch
psia	Pounds per square inch (absolute)
PSL	Plant St. Lucie
PSP	Physical Security Plan
PWO	Plant Work Order
PWSCC	Primary Water Stress Corrosion Cracking
QA	Quality Assurance
QC	Quality Control
QI	Quality Instruction
QSL	Quality Surveillance Letter
RAS	Recirculation Actuation Signal
RCB	Reactor Containment Building
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
Rev	Revision
RFO	Refueling Outage
RII	Region II - Atlanta, Georgia (NRC)
RM	Radiation Monitor
RPV	Reactor Pressure Vessel
RTGB	Reactor Turbine Generator Board
RWT	Refueling Water Tank

SDC	Shut Down Cooling
SG	Steam Generator
SGBD	Steam Generator Blowdown System
SIAS	Safety Injection Actuation System
SIT	Safety Injection Tank
SNO	Short Notice Outage
SNPO	Senior Nuclear Plant [unlicensed] Operator
SRI	Senior Resident Inspector
SRO	Senior Reactor [licensed] Operator
SRP	Standard Review Plan
SRV	Safety Relief Valve
St.	Saint
STA	Shift Technical Advisor
STAR	St. Lucie Action Request
TC	Temporary Change
TCN	Temporary Change Notice
TS	Technical Specification(s)
UGS	Upper Guide Structure
URI	[NRC] Unresolved Item
VAR	Reactive Load
VIO	Violation (of NRC requirements)
WG	Water Gauge