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

Report Nos.: 50-335/95-07 and 50-389/95-07

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: March 5 through April 1, 1995

Lead Inspector: R. L. Prevatte, Senior Resident Inspector — 4/13/95 Date Signed

Accompanying Inspectors:

Julio F. Lara, Resident Inspector, Watts Bar
Mark S. Miller, Resident Inspector
Robert P. Schin, Project Engineer, NRC Region II
Malcolm T. Widmann, Resident Inspector, Vogtle

Approved by: K. D. Landis — 4/18/95 Date Signed
K. D. Landis, Chief
Reactor Projects Section 2B
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection was conducted on site 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:

Operations were conducted well during the inspection period. Unit 1 experienced a loss of shutdown cooling event, and the licensee's root cause investigation was found to be objective, thorough, and timely. The event resulted in a non-cited violation relating to

procedure compliance. The restart of Unit 1 following a maintenance outage was found to be well controlled. A post-trip review meeting, conducted to develop corrective actions to the February 21 trip of Unit 2 involving approximately 50 personnel from a number of departments, was an innovative approach to problem solving.

Maintenance and Surveillance area:

A loss of configuration control was identified by the licensee, involving the failure to remove a temporary switch from an electrical circuit, and resulted in a non-cited violation. A weakness was identified in procedural guidance provided for the performance of a preventive maintenance activity. Surveillances were performed satisfactorily.

Engineering area:

One plant modification, involving the modification of diesel generator loss-of-field relays, was reviewed by the NRC and found satisfactory.

Plant Support area:

Plant support activities continued to be conducted satisfactorily. The licensee's fire brigade promptly responded to and extinguished a fire in the Unit 1 pressurizer cubicle.

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

NCV 335/95-07-01,	"Failure to Follow Shutdown Cooling Operating Procedures," paragraph 3.f
NCV 335/95-07-02,	"Failure to Maintain Configuration Control of Unit 1 ECCS Area Ventilation Electrical Circuit," paragraph 4.a.1.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*R. Ball, Mechanical Maintenance Supervisor
*E. Benkin, Plant Licensing Engineer
*W. Bladow, Site Quality Manager
*L. Bossinger, Electrical Maintenance Supervisor
H. Buchanan, Health Physics Supervisor
*C. Burton, St. Lucie Plant General 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
K. Heffelfinger, Protection Services Supervisor
G. Madden, Plant Licensing Engineer
J. Marchese, Maintenance Manager
W. Parks, Reactor Engineering Supervisor
C. Pell, Outage Manager
*L. Rogers, Instrument and Control Maintenance Supervisor
*D. Sager, St. Lucie Plant Vice President
*J. Scarola, Operations Manager
*D. West, Technical Manager
*J. West, Site Services 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

K. Landis, Chief, Reactor Projects Branch 2, NRC Region II
J. Lara, Resident Inspector, Watts Bar
* M. Miller, Resident Inspector
R. Prevatte, Senior Resident Inspector
S. Sandin, Senior Operations Officer, AEOD
R. Schin, Project Engineer, USNRC Region II
W. Tobin, Senior Physical Security Specialist, NRC Region II
* M. Widmann, Resident Inspector, Vogtle

* Attended exit interview

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

2. Plant Status and Activities

a. Unit 1

On March 8, Unit 1 returned to power operations following an eight day Short Notice Outage for the replacement of pressurizer code safety valves. The unit operated at essentially full power for the balance of the inspection period.

b. Unit 2

Unit 2 operated at essentially full power throughout the inspection period.

c. NRC Activity

During this period, an inspection of the licensee's Security program was conducted from March 27 to 31 by W. Tobin of NRC Region II. The inspection results were reported in IR 335,389/95-08.

Kerry D. Landis, Acting Chief, Reactor Projects Branch 2, NRC Region II, visited the site on March 29. His activities included a meeting with the Site Vice President and delivering the keynote address at a graduation ceremony for newly licensed operators.

Robert P. Schin, Project Engineer, NRC Region II, visited the site from March 6 through 10. Julio F. Lara, NRC Resident Inspector/Watts Bar, visited the site from March 20 through 24. Malcolm T. Widmann, NRC Resident Inspector/Vogtle, visited the site from March 27 through 31. Their activities included augmenting the resident inspection effort and are detailed in this report.

d. Plant Management Training

During the period, a number of plant managers and supervisors began a six-month plant systems training course. Temporary (acting) managers were named as follows:

- L. Rogers, I&C Supervisor, will be acting for J. Marchese, Maintenance Manager
- C. Mohindroo, Site Chief Engineer, will be acting for D. Denver, Engineering Manager
- R. Gross, Steam Generator Replacement Engineer, will be acting for D. Sipos, Steam Generator Replacement Project Manager

3. Plant Operations

a. 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. The frequency of plant tours and control room visits by site management was noted.

The inspector performed walkdown inspections of system flow path valves to confirm equipment lineups. The valves verified were associated with Unit 2 LPSI and CS systems. These valves were verified to be in the correct position as reflected in system flow diagrams 2998-G-078, 2998-G-088 and by position tags located on the valves. Inspection attributes included valve position, presence of locking devices as required, and verification that the valve positions were in accordance with licensee requirements for system operability as defined in the Unit 2 Technical Specifications. Equipment conditions were determined to be acceptable.

The inspector also performed walkdown inspections of other plant areas including Unit 2 EDG rooms, Units 1 and 2 electrical switchgear rooms, Unit 2 AFW pump rooms, Units 1 and 2 electrical penetration rooms, and Unit 1 safe shutdown panels. The areas inspected were observed to be clean and free of obstructions. At the safe shutdown room, operating procedures were available. The inspector verified that the procedures were controlled copies and were the latest approved revision. The procedures verified were:

- ONOP 1-0030135, Rev 20, Control Room Inaccessibility
- OP 1-0030127, Rev 66, Reactor Plant Cooldown-Hot Standby to Cold Shutdown

b. 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.

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.

No violations or deviations were identified.

d. Clearances (71707)

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

- 2-95-03-58 - Clearance on BA gravity fuel valves (V2508, V2509) from BAM to permit MOV maintenance and VOTES testing.
- 1-95-03-46 - Containment purge supply isolation valve.

Tags were in place and fuses, valves, and breakers were correctly positioned as required by the applicable clearance.

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. Unit 1 Loss of Shutdown Cooling (71707)

On March 4, Unit 1 experienced a loss of shutdown cooling while realigning shutdown cooling trains. The event lasted approximately 14 minutes. Initial RCS conditions were 99°F and 247 psia. The RCS was in a solid water condition, with pressure being maintained through CVCS letdown pressure control. Peak RCS temperature during the event was 113°F and peak pressure was 343 psia.

At 9:35 p.m., an RCO was placing the A SDC train in standby after placing the B SDC train in service. OP 1-0410022, Rev 19, "Shutdown Cooling," section 8.2 described the method for placing one SDC train in standby with the other train in service. The methodology (presented in the order specified by the procedure) involved securing the pump in the train of interest, verifying adequate SDC flow remained, shutting the affected pump's discharge valve, and then shutting the affected pump's suction valve.

The performance of these steps required operation at two different control panels; the CRAC which contained controls for LPSI pump discharge isolation valves, and RTGB 106 which contained controls for LPSI pumps and LPSI pump suction isolation valves. The two panels were located at extreme ends of the Unit 1 control room, requiring operators to traverse the control room in the course of placing a train in standby. The SDC realignment was being conducted by the Desk RCO, one of two reactor operators on watch at the time. The other reactor operator, the Board RCO, was dedicated to monitoring RCS pressure and controlling letdown flow, as the unit was in a solid water condition.

A timeline was established, by the licensee, for the event based upon interviews with the operating crew, output from the SOER, and ERDADS. Major aspects of the timeline are as follows:

21:41:20	Desk RCO secures 1A LPSI pump
21:42:20	Annunciator - V3651 (1B LPSI pump SDC suction isolation valve) closing with 1B LPSI pump running
*	Desk RCO goes to CRAC to shut A SDC discharge valve
21:43:20	No SDC flow registered on SDC flow instrument (<1500 gpm)
*	Desk RCO returns to RTGB 106
*	Board RCO notes pressure increasing
*	Board RCO goes to RTGB 106 and notes annunciator
*	Board RCO goes to CRAC to verify valve positions
*	Board RCO returns to RTGB 106, then to RTGB 104
*	Desk RCO notifies crew of mid-position indication of V3651
21:43:42	Annunciator - V3651 permissive not met - pressure >270 psia
*	Board RCO notes pressure at 320 psia and increases letdown
21:44:35	Annunciator - LTOP anticipatory - pressure >330 psia
21:44:44	Desk RCO secures 1B LPSI pump
*	Desk RCO notes again, and crew acknowledges, dual indication of V3651
21:44:50	RCS peak pressure reached - 343 psia
21:45:00	Board RCO secures 1B charging pump
21:45:41	V3651 open permissive satisfied
21:58:40	SDC > 3000 gpm restored

* time not precisely established, but sequential based upon interviews

The licensee concluded that the loss of SDC was the direct result of V3651 closing. ERDADS data, indicating reductions in SDC flow, combined with SOER data would support the conclusion. In considering the cause for the valve closure, the licensee pursued parallel paths which considered electrical malfunction and operator error.

With regard to possible electrical malfunction, the licensee composed two independent cross-functional teams to consider failure scenarios which might lead to the closure of V3651. The teams analyzed the control circuitry for the valve and postulated electrical faults that might result in valve closure. Field tests for insulation between individual conductors and between conductors and ground were conducted with satisfactory results. Additionally, inspections were made of valve limit switch components and physical conditions at the valve. No deficiencies were noted. The two teams concluded that there was no credible electrical fault that could lead to the noted valve closure.

The licensee then conducted two additional reviews of the circuitry by engineering personnel not previously associated with the event. Similar conclusions were reached. The inspector reviewed the applicable control wiring diagram for V3651 and determined that the licensee's conclusions were sound. The inspector further concluded that any electrical fault which may have lead to valve closure must have existed for a period of approximately 60 seconds (the valve's stroke time) and then cleared, allowing the valve to open.

The licensee convened a meeting of the crew on watch during the event, provided a facilitator and ERDADS/SOER data and tasked the crew with creating possible scenarios which could lead to the noted behavior. The crew determined that the only credible cause for the event would involve a mispositioning of the key-lock control switch for V3651, followed by a return of the valve's control switch to the open position after the valve had cycled closed. Given the timeline for the event and the results of crew interviews, the only person in a position to make such an error was the Desk RCO.

The mispositioning would involve the Desk RCO securing the 1A LPSI pump and attempting to close V3481 (the 1A LPSI pump SDC suction isolation valve) prior to moving to the CRAC to close the 1A discharge isolation valve. Instead of closing V3481, the Desk RCO would have to mistakenly operate the control switch for V3651. This would appear credible, as the two switches are oriented beside one another on RTGB 106. This scenario would allow V3651 to stroke closed while the Desk RCO moved to the CRAC and would result in the first annunciator noted. This scenario would also represent a departure from the governing procedure, as the suction valve is listed as the last valve to be operated in placing a SDC train in standby.

The scenario in question would further require the Desk RCO to realize his error upon returning to RTGB 106 and return the control switch for V3651 to the open position in an attempt to correct the error. Given that RCS pressure exceeded the pressure interlock associated with V3651, the valve would fail to cycle completely open until pressure was reduced below the interlock setpoint. This would explain the dual position noted by both the Desk RCO and the crew.

The Desk RCO was presented with the licensee's conclusions and maintained that he did not misposition V3651. The licensee relieved the Desk RCO of licensed duties and placed him on suspension with pay while investigations were being conducted. As data began to indicate that electrical malfunction was not credible, the licensee withdrew the Desk RCO's site access. The licensee later elected to take strong disciplinary action against the operator. The operator resigned prior to disciplinary action taking place.

The safety consequences of this event were minor. TSs were not violated. TS 3.4.1.4.1 required, in Mode 5 with RCS loops filled, at least one shutdown cooling loop be operable and either one additional shutdown cooling loop be operable or secondary side water level of two steam generators be greater that 10 percent of narrow range indication. During this event, both shutdown cooling loops were operable, RCS loops were filled, and both steam generators had water level greater than 10 percent of narrow range indication. TS 3.4.1.4.1 also required that at least one shutdown cooling loop be in operation. With no shutdown cooling loop in operation, Action Statement b. allowed one hour to initiate corrective action to return the required shutdown cooling loop to operation. In this event, one shutdown cooling loop was restored to operation in about 14 minutes.

The inspector concluded that the licensee's actions in response to this event were timely, thorough, and objective. Due consideration was paid to the potential for equipment failure as a root cause for the event. The inspector found that the licensee's conclusion that operator error was the root cause reflected the only plausible explanation for the event. The inspector further concluded that operator response to annunciator R-30, "LPSI PP 1B RUNNING/V-3651/3652 CLOSING," was weak, in that the actions recommended in the annunciator response procedure (checking valve positions, securing the operating pump) were not fully carried out until more than two minutes following the annunciation. Had the actions been carried out at the time of the annunciation, the event may have been prevented.

The attempted closing of valve V3481 (valve 3651 was actually closed instead) following the securing of the 1A LPSI pump represented a failure to follow procedure OP 1-0410022, Rev 19, "Shutdown Cooling," in that valve V3206 (the 1A LPSI pump discharge valve) should have been closed first. This represented a violation of Technical Specification (TS) 6.8.1.a, which required that written procedures be established, implemented, and maintained covering, in part, procedure adherence. Procedure QI 5-PR/PSL-1, Rev 60, "Preparation, Revision, Review/Approval of Procedures," Section 5.13.2 stated that all procedures shall be strictly adhered to. This violation will not be cited because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B of the NRC enforcement policy. It will be identified as NCV 335/95-07-01, "Failure to Follow Shutdown Cooling Operating Procedures."

g. Unit 1 Startup (71707)

The inspectors observed the Unit 1 startup on March 8. Licensee personnel conducted the evolution in a deliberate and well-controlled manner. They delayed the startup to get FRG approval to reset the alarm point for the 1A1 RCP seal so that the alarm would stop constantly coming in and out and disturbing the operators during the startup. An SRO, who was designated as the reactivity manager, and a reactor engineer augmented the normal control room staff and each applied their full attention to the startup. A 1/M curve was plotted by the reactor engineer, and it worked well in providing a periodic assessment of the status of the startup with respect to the ECP. The reactor was brought critical at 5:15 a.m. at 65 inches on group 7, which was very close to the ECP of 60 inches on group 7.

h. Post-Trip Review Meeting (71707)

On March 29, the inspector attended a post-trip review meeting covering the February 21 automatic trip of Unit 2 due to the failure of a steam generator level transmitter. The meeting was attended by the President of the licensee's Nuclear Division, the Site Vice-President, the Plant General Manager, a number of other key managers in the licensee's organization, and approximately 50 personnel from the areas of training, operations, maintenance and engineering. The meeting's purpose was to thoroughly review the trip with the goal of identifying areas of improvement to prevent future occurrences.

The meeting included the showing of a video recreating the event in the licensee's simulator, displaying alarms and plant response. The meeting then took the form of an open discussion, in which all parties offered ideas for improvement. The meeting resulted in the identification of a number of potential enhancements in the areas of annunciators, shift staffing, control board component placement, and unit standardization. The inspector concluded that the meeting was an innovative approach to problem solving.

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

Facility Review Group Meetings

The inspector attended the FRG meeting conducted on March 15. This meeting covered several LERs and an LOI involving the resin intrusion into the RWT and spent fuel pool areas. A quorum was present and extensive questioning occurred on one LER. The LER did not appear to be of final submittal quality and several technical and administrative changes were made by the FRG.

j. Followup of Operations LERs (92700)

1) (Closed) LER 50-335/93-09-00 and 93-09-01: Engineered Safety Features Actuation due to Spurious Subgroup Actuation Module Trip

On November 13, 1993, Unit 1 experienced a spurious ESF actuation of an ESAS CIS subgroup channel and the following resulting automatic actions: control room ventilation system shift to recirculation, reactor cavity sump isolation valve closing, and reactor drain tank isolation valve closing. At the time, the unit was at 98 percent power and one of four containment radiation measurement bistables was in trip for maintenance on channel MA. With the containment radiation CIS logic then requiring one of the remaining three channels to trip, a temporary signal spike in containment radiation monitoring channel MB caused the 4B CIS subgroup actuation module to latch in. The licensee replaced the 4B CIS subgroup actuation module and subsequent licensee and vendor examination of the removed module found no indication of faulted components. The licensee also monitored the radiation monitoring channels and detected no indication of inadequate performance. The licensee attributed the root cause to a spurious voltage spike. The inspector discussed the issue with I&C maintenance personnel, who stated that since that event there have been no similar problems with the Unit 1 CIS radiation monitors or associated subgroup channels. Also, they stated that Unit 2 had different radiation monitoring equipment and had not experienced this problem. This LER is closed.

2) (Closed) LER 50-389/93-07 and 93-07-01: Manual Reactor Trip After the Simultaneous Dropping of Control Element Assemblies due to Equipment Failure

On May 21, 1993, Unit 2 was manually tripped from 72 percent power after seven CEAs dropped into the core. The CEAs dropped due to electrical grounds in the CEA cables in electrical penetration D-1 to the containment shield building. This event, subsequent CEA cable testing and repairs, and Unit 2 restart are documented in IRs 50-335,389/93-12 and 93-15. During the next Unit 2 refueling outage, the licensee disassembled and inspected the affected cables and found no root cause for the failures. In addition, two of the defective cable assemblies were sent to the manufacturer for failure analysis. The inspector reviewed the failure analysis report, in which the manufacturer could not determine a root cause for the low insulation resistance. The inspector also discussed the event with licensee electrical and I&C engineers, who described how, since the event, the licensee has performed monthly voltage checks of each phase to ground of the CEA motor generator outputs on each unit. These monthly checks have revealed no electrical faults to ground or between phases in the CEA power supply cables. In addition, the licensee has continued to perform meggar checks of CEA cables during each refueling outage. The licensee had investigated installing a permanent ground detector in each unit, but decided against it because of cost. Instead, the licensee plans to continue the monthly voltage checks and the refueling outage meggar checks. This LER is closed.

3) (Closed) LER 50-335/94-03: Automatic Reactor Trip Caused by Manipulation of the Main Generator Breaker Exciter Field Breaker due to Cognitive Personnel Error

On March 28, 1994, Unit 1 automatically tripped from 68 percent power when a chief electrician erroneously opened the main generator exciter breaker. Unaware that he was on the wrong unit, the chief electrician tried to verify what he thought was the appropriate position of the breaker for a work clearance on Unit 2 by attempting to open the breaker. As documented in IR 50-335,389/94-12, an uncomplicated automatic trip of Unit 1 resulted. The licensee disciplined the individual and restarted the unit. In addition, the inspector reviewed a licensee HPES analysis of the event and observed that additional "Unit 1" or "Unit 2" signs had been appropriately placed at each unit's main generator exciter breaker and in other areas of each unit. This LER is closed.

4) (Closed) LER 50-389/94-01: Pressurizer Auxiliary Spray Out of Service Caused by a Mispositioned Isolation Valve Due to Personnel Error

On February 17, 1994, with Unit 2 in mode 5, operators found that pressurizer auxiliary spray did not work due to auxiliary spray manual isolation valve V2483 being mispositioned locked closed. This event was documented in IR 50-335,389/94-05 and was tracked as NCV 50-389/94-05-01. Licensee corrective actions included operations and quality control inspectors performing a walkdown of accessible Unit 2 valves prior to returning Unit 2 to service. In addition, since that time, operations and quality control inspectors verified the correct position of Unit 1 locked valves during the next Unit 1 outage. The inspector reviewed a licensee record of that inspection, which found no mispositioned valves. This LER is closed.

5) (Closed) LER 50-389/94-03: Automatic Reactor Trip During Functional Testing of the Reactor Protective System Due to Bypass Miswiring During Original Construction

On April 23, 1994, Unit 2 automatically tripped from 29 percent power during I&C performance of a linear power range safety and control channel monthly calibration procedure. The licensee determined the cause of the trip to be an improperly wired bypass circuit on the RPS channel B local power density bistable. This event and the licensee's immediate corrective actions were documented in IR 50-335,389/94-12. Since then, the licensee additionally tested all Unit 1 RPS channel bypass circuits and found no discrepancies. The inspector reviewed a licensee summary of this test and discussed it with I&C personnel. This LER is closed.

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) HVE-9B ECCS Ventilation Outlet Damper L-7B

On March 29, HVE-9B ECCS area exhaust air filter train B was returned to service following maintenance work on L-7B discharge damper. Inadequate configuration control of the ventilation system electrical damper circuit during maintenance resulted in Operations returning the system to service with a temporary switch still installed.

On March 28, HVE-9B fan was removed from service due to the failure of discharge louvre L-7B to open on a start signal from the control room during surveillance 1-0010125, Rev 100, "Schedule of periodic Tests, Checks and Calibrations," Check Sheet 4, "Test ECCS Area Ventilation System, B Train." Operations entered the seven day action statement of TS 3.7.8.1 to troubleshoot the damper problem.

Troubleshooting identified a bad motor on the L-7B damper. Electrical maintenance installed a new motor, but discovered mechanical binding of the damper during the performance of a subsequent surveillance. The L-7B damper would not completely close. Electrical maintenance requested mechanical maintenance assistance to repair the mechanical binding of the damper linkage. During the performance of these maintenance activities, electrical technicians installed a temporary switch to allow mechanical maintenance to open and close the damper as needed to adjust the linkage. This allowed local control by mechanical maintenance without electrical maintenance personnel present.

After completion of the mechanical portion of the damper work, the mid-shift mechanical maintenance supervisor released the mechanical and electrical clearances on the HVE-9B ventilation fan. No communications with the electrical department transpired to verify whether or not the electrical PWO to support the mechanical portion of the work package was completed prior to release of the electrical clearance. The Unit 1 ANPS assumed all work was complete due to the mechanical maintenance supervisor releasing the mechanical and electrical clearances and he exited the LCO action statement by completing a post maintenance surveillance satisfactorily for the fan and damper. All indications were that the fan and damper operated correctly and the ventilation system was placed in service.

The temporary switch, however, remained installed in the damper circuit in the "on" position, which allowed the post maintenance surveillance to be completed successfully without the Unit 1 ANPSs recognizing that the electrical circuit had not been restored to the original system design after the completion of the maintenance activity. On March 29, the day shift NPS was informed by the Electrical Maintenance Supervisor that the temporary switch was still installed in the HVE-9B damper circuit. The NPS removed the HVE-9B fan from service, re-entered the Action Statement, and had the temporary switch removed from the damper circuit. The Unit 1 HVE-9B ECCS area ventilation train B system was then returned to service after the completion of a second post maintenance surveillance test, performed on March 29.

The inspector investigated the causal factors that contributed to the ECCS ventilation fan electrical circuit not being controlled. The inspector determined through discussions with electrical and mechanical maintenance personnel, operations personnel and licensee management that the loss of configuration control resulted from breakdowns in several different areas. The electrical maintenance PWO scope used to support the mechanical maintenance during damper troubleshooting was not revised as required by AP 0010432, Rev 78, "Nuclear Plant Work Orders," when the temporary switch was installed in the circuit. Electrical personnel did not use the jumper/lifted lead process to document the temporary switch in the circuit as required by procedure 0010124, Rev 34, "Control and Use of Jumpers and Disconnected Leads." The release of the electrical clearance by the mechanical maintenance supervisor without verification that the electrical PWO was completed contributed to the breakdown in configuration controls. Licensee management not clearly delineating expectations and responsibilities of supervisors on peaks and midnight shifts contributed to the event. Poor communications between electrical and mechanical maintenance organizations and Operations led to confusion on the status of both the mechanical and electrical NPWOs status. The ANPS did not independently verify the component status versus system status other than the clearances being released by maintenance supervisors. This led the ANPS to believe the system was ready to be returned to service.

The licensee initiated STAR 950361 to document the issue and to develop corrective actions. In-House Event Summary 95-016 was prepared with a narrative description of the event and a determination of the cause and corrective actions. Corrective actions included:

- removal of the switch and satisfactory surveillance testing of HVE-9B
- Counseling the mid-shift electrical maintenance chief on the inappropriate use of an uncontrolled jumper
- A review of open electrical maintenance NPWOs to ensure similar instances did not exist.
- Counseling the mid-shift mechanical maintenance supervisor on the correct methods of removing clearances
- Surveying other maintenance chiefs and supervisors on their knowledge of the use of jumpers and lifted leads and resolving any areas of confusion discovered
- Considering modification of the equipment out-of-service log to include references to all applicable NPWOs
- A letter from the Maintenance Manager to maintenance supervisors and foremen discussing the event and delineating expectations for backshift supervisors

The licensee's failure to maintain configuration control of the electrical circuit on the safety related HVE-9B ECCS area ventilation Train B system represents a violation of 10

CFR 50 Appendix B, Criterion III, Design Control. This violation will not be cited because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B of the NRC enforcement policy. The non-cited violation will be identified as NCV 50-335/95-07-02, "Failure to Maintain Configuration Control of Unit 1 ECCS Area Ventilation Electrical Circuit."

2) NPWO 62/2728 Charging Pump 2B Suction/Discharge Accumulator Preventive Maintenance

The inspector observed the performance of Unit 2 charging pump 2B suction and discharge accumulator PM on March 28. Work was performed per mechanical maintenance procedure 2-M-0018, Rev 42, "Charging Pump Accumulators 2A, 2B, & 2C Pressure Check/Recharge."

The procedure required the use of M&TE equipment to measure the as-found (initial) and as-left (final) accumulator pressures. The technicians were required to coordinate the opening and closing of the nitrogen supply header valve (to charge the accumulators) with control room personnel.

The suction accumulator stabilizer as-found pressure was measured at an abnormally low value of approximately 4 psig. Procedure guidance acceptance criteria was 25 to 29 psig. After noting the as-found condition, maintenance continued with the procedure and charged the accumulator to within the acceptance criteria. The discharge accumulator measured low at 1560 psig. The acceptance criteria was 1625 to 1675 psig. The technicians properly charged both 2B charging pump accumulators per procedure 2-M-0018.

The inspector discussed the as-found condition of the suction accumulator with the maintenance chief and system component engineer. The suction accumulator bladder had been replaced on February 28, 1995. The inspector expressed a concern that the as-found pressure may indicate a fault in the bladder. The component engineer suspected that the metal plug in the bottom of the bladder may have started to leak or that the valve stem may not be seated properly. However, no immediate actions were taken by maintenance personnel to determine if a leak existed on March 28. The system component engineer did listen to the operation of the accumulator stabilizer the next day for problems. Based on discussions with the licensee, the component engineer planned to continue to monitor the 2B accumulator bladder pressure for evaluation of accumulator stabilizer performance. Also, corrective action by the system component engineer, as part of STAR 950369, recommended that a revision to the PM procedure be made, enhancing the maintenance instructions to allow mechanics to test the

bladder when a potential leak is suspected during the PM (e.g, as-found condition of 4 pounds). No provision to test for suspected accumulator leaks existed in the procedure.

The inspector considered the maintenance procedural guidance to be weak in delineating direction to the mechanics in the event that potential problems are identified during the PM. The lack of a questioning attitude by maintenance personnel allowed the facts relating to the as-found condition to remain within the maintenance department until the inspector questioned the licensee as to troubleshooting or diagnosis.

The overall performance of the PM was conducted in accordance with the procedure and performed well with the exception of the lack of maintenance actions for the as-found condition. The PWO was completed and the post maintenance test was conducted satisfactorily. The inspector did not identify any other concerns during the maintenance observations or review of the work package.

3) NPWO 61/4425 Replacement of Charging Pump 1B Accumulator Bladder

The inspector observed maintenance work on the Unit 1 charging pump 1B suction accumulator on March 29. Work was performed per vendor technical manual procedure 8770-9596, Rev A, "10 Gallon Stainless Steel 150 PSIG Suction Stabilizer Charging Pump Accumulators 2A, 2B, & 2C Pressure Check/Recharge."

The inspector reviewed the maintenance work package, the associated clearance, and the vendor technical manual. During replacement of the 1B suction stabilizer bladder, maintenance personnel encountered problems in removing the cap on the top of the accumulator. The procedure had the mechanics release nitrogen pressure from the bladder, remove the valve core, and then unscrew the accumulator cap. However, the technician failed to remove the valve core, which left pressure in the bladder and resulted in the cap being difficult to remove. Once the technician realized the error, he removed the valve core and completed the replacement without complication. The licensee initiated STAR 950362 to review the maintenance work practices and individual mechanic compliance to procedures during performance of the charging pump PWO.

The inspector's assessment of the failure to remove the accumulator valve core was that it did not result in a safety significant problem or a personnel safety issue. The failure to remove the valve core only resulted in difficulty in the removal of the accumulator cap. The remaining portions of the accumulator stabilizer bladder replacement were completed satisfactorily. HP controls established for, and maintained throughout, the performance of the maintenance activity were considered good. The inspector did not identify any other concerns during the maintenance observations or review of the work package.

4) NPWO 65/0712 Preventive Maintenance of 1A, 1B, 1C, and 1D 125 Volt DC Batteries

The inspector reviewed work packages for the weekly battery inspection of 125V DC batteries 1A, 1B, 1C and 1D. Work was performed per mechanical maintenance procedure 0960163, Rev 13, "125 V DC System Weekly Maintenance." The completion of the maintenance inspection satisfied requirements of TS 4.8.2.3.2.a and Table 4.8-2.

The inspector reviewed the documentation to verify that the weekly inspection was performed in accordance with written procedures and that battery integrity had been maintained. Data recorded for the inspection included specific gravity, electrolyte temperature, electrolyte level, and battery terminal voltage. Visual checks were performed by electricians to ensure the batteries were free of corrosion on inner cells.

The inspector's review concluded that the battery inspection was completed satisfactorily and the recorded data were within procedure limits. The inspector verified that M&TE were within their calibration periods. The inspector considered the battery inspection procedure to have appropriate procedural guidance to perform the inspection. The inspector did not identify any items of concern during the review.

5) PWO 69/4185 - Build Shed for Valve Test Bench

The inspector reviewed this PWO and observed some of the work in progress for building a shed, attached to the F-4 warehouse, for a valve testing bench. The bench was intended for testing secondary system relief valves, both safety and non-safety related. The shed construction work was non-safety related and the licensee's nuclear QA program did not apply. This facility will enhance the licensee's maintenance work area.

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 tests were observed:

1) OP 2-0700050, Rev 37, "Auxiliary Feedwater Periodic Test"

   The inspector observed AFW pump testing, conducted March 21 on Unit 2. The testing was performed to satisfy the requirements within AP 0010132, Rev 18, "ASME Code Testing of Pumps and Valves." The code testing requires the running of the AFW pump for a minimum of 5 minutes after which pump performance is to be compared against the pump baseline data. The tests observed were performed on Unit 2 AFW motor-driven pumps 2A and 2B.

   The inspector reviewed the test procedures and discussed the scope of testing with the operators. The inspector reviewed the pump performance test results and confirmed that the acquired performance data (pump suction, discharge, and differential pressures) met the acceptance criteria.

2) OP 2-2200050B, Rev 16, "2B Emergency Diesel Generator Periodic Test and General Operating Instructions"

   The inspector observed the performance of 2B EDG surveillance test performed on March 22. The EDG test was performed following the implementation of modification PC/M 138-294M and prior to returning the EDG to service.

   The inspector observed the preparations being made for the EDG run. The SNPO performed the prerequisite checks and recording of data as prescribed by the procedure. The SNPO started the EDG in accordance with step 22 which consisted of a local start and warmup prior to loading. The EDG was verified to idle at 375 - 475 RPM prior to releasing the idle. The EDG reached approximately 900 RPM, nominal voltage and frequency. The EDG was then synchronized to the offsite power system and set to carry real and reactive loads in accordance with the limits provided in the procedure (3450 to 3685 kW while maintaining 0.5 to 1 MVAR lagging). The inspector independently verified that the EDG was operating while supplying a load of approximately 3650 kW and 1000 kVAR.

   The EDG was loaded for at least one hour and the inspector reviewed the recorded data and verified that measured parameters met the expected limits. Parameters include jacket water temperatures, lube oil temperatures, and cylinder exhaust temperatures. The EDG was subsequently unloaded and shutdown in accordance with the EDG procedure instructions. No deficiencies were identified with the performance of the test.

The inspector also reviewed the operator logs and performed a control room board review to determine the status of the redundant 2A EDG and other train A equipment. The inspector verified the availability of 2A HPSI pump and flowpath, 2A LPSI pump and flowpath, 2A EDG, and 2A CS pump and flowpath. Review of the operator log identified that after taking the EDG out of service at 0554 hrs, HVE10A, HVS4A, and HVS3A were briefly taken out of service. The inspector verified that these components were not included in Appendix B of OP 2-2200050B. Appendix B identifies the equipment that must be in service prior to removing the 2B EDG from service.

3) OP 2-0400053, Rev 19, "Engineered Safeguards Relay Test"

The purpose of this test was to verify proper functioning of Unit 2 ESF relays as required by Technical Specification Surveillance Requirement 4.3.2.1. This surveillance requirement requires the performance of ESFAS functional tests as specified in Table 4.3-2. In accordance with the TS requirements, this test was being performed to meet the semi-annual frequency (at least once per 184 days) for ESFAS functional tests.

On March 23, the licensee performed the ESFAS functional test which required the automatic actuation of HPSI, LPSI, and CS pumps. The inspector accompanied the SNPO during the restoration of equipment lineups following the testing of train A pumps, and during the lineup and restoration of train B pumps.

With respect to train A ESFAS testing, the inspector observed the restoration of valve lineups including the opening of the CS pump 2A discharge valve and providing locking devices. These actions were performed in accordance with the instructions in Data Sheet 3A of OP 2-0400053. The inspector also accompanied the SNPO during the valve alignment prior to the starting of the train B ESFAS actuation (Data Sheet 3B of OP 2-0400053). This included closing the normally locked open CS pump 2B discharge valve. Following the starting of the HPSI, LPSI, and CS 2B pumps, operating data was taken at the control room followed by the securing of the pumps.

The inspector verified that the SNPO properly re-aligned the affected valves to the correct positions, including the opening of CS pump 2B discharge valve and installation of a locking device. The inspector observed that the valve lineup restoration was accomplished in accordance with the procedure requirements followed by an independent verification by a Watch Engineer.

c. Followup of Maintenance LERs (92700)

(Closed) LER 50-389/94-04: Plant Vent Wide Range Monitor Out of Service due to Personnel Error

On June 28, 1994, with Unit 2 at 100 percent power, I&C personnel discovered during a routine calibration that the plant vent wide range gas monitor (WRGM) low and high range sample lines were disconnected. The lines had been disconnected since the previous calibration on April 6, 1994. This event was discussed in IR 50-335,389/94-14 and was identified as NCV 50-389/94-14-02, Inoperable WRGM Due to Maintenance Error.

The licensee placed the plant vent WRGM back in service, checked the sample lines on all other process radiation monitors on both units, and found no other disconnected lines. The licensee revised the I&C calibration procedure to include independent verification of the reconnection of the sample lines. Also, the licensee revised the operations procedures for controlled gaseous batch release to atmosphere to include a channel check of plant vent radiation monitors before and during all planned releases. The inspector verified that the above procedure changes had been made. This LER is closed.

d. Followup on Previous Maintenance Findings (92902)

Discrepant Material Found in Rosemount Transmitters

IR 94-24 documented the nearly simultaneous failures of two Unit 1 Rosemount pressure transmitters which resulted in the initiation of a SIAS while the unit was in Mode 5. IR 94-25 documented the examination of the sensing elements on site and the discovery of distended isolation diaphragms, which indicated potential gas intrusion into the transmitters' sensing cells. During the inspection period, one of the transmitters' sensing element was sampled at Southwest Research Institute in an attempt to determine the nature of the apparent gas. The conclusion was that the gas was pure diatomic hydrogen.

A sample of the transmitter's fill oil indicated that the hydrogen was not the result of oil breakdown or water in the oil. A metallurgical analysis was performed on the isolator material, which was found to be Monel, an alloy susceptible to hydrogen permeation. The transmitters in question were to have been fabricated with stainless steel isolators.

As a result of these findings, it was determined, by Rosemount, that at least 450 transmitters were similarly configured. The subject was addressed in IN 95-20.

As a result of the 10 CFR 21 report transmitted by Rosemount, the licensee determined that a number of transmitters with Monel 400 isolators were employed at St. Lucie in safety-related applications. Unit 1 applications included:

- 1 Pressurizer Pressure Safety Channel (RPS/ESF input)
- 1 Pressurizer Pressure Control Channel
- 2 LTOP Channels
- 7 of 8 Steam Generator Pressure Safety Channels (RPS/ESF input)

Unit 2 applications included one LTOP channel. The licensee evaluated the existing applications and developed a replacement strategy based upon the existence of spare transmitter sensing cells. The licensee's plan called for the replacement of LTOP channels first, as a failure of these transmitters in cold shutdown conditions would lead to a PORV lift.

The licensee performed an operability assessment of the discrepant transmitters in service in both units and concluded that they were all operable. The assessment, as well as the actions taken relative to the issue, was performed under STAR 95-0310. The inspector reviewed the assessment and found it to reflect the current industry understanding of the issue.

The inspector concluded that the licensee has been proactive in addressing this issue, which required rapid generic consideration. The licensee's actions reflected well on their commitment to root cause determination and has resulted in a net safety benefit to the industry as a whole. The inspector will continue to follow the licensee's actions with regard to this issue.

5. Engineering Support (37551)

a. Onsite Engineering

The inspectors and the Turkey Point resident staff attended a meeting with the licensee's Onsite and Corporate Engineering organization at the Turkey Point Plant on March 14. At this meeting the licensee provided the resident staffs with an update on their plan and project status for the following items:

- Thermolag
- Reactor vessel neutron embrittlement
- NRC Generic Letter 89-10
- Maintenance Rule
- Current site engineering issues
- Turkey Point self assessment

- Design basis documents
- Operator workarounds
- Turkey Point instrument air upgrade
- Abandoned equipment
- Turkey Point EDG sequencer issue
- FPL future power needs and plans
- Plant life extension
- Turkey Point thermal uprate
- 24 month fuel cycles
- Spent fuel storage

A short presentation was provided on each of the above items and resident questions were answered by the licensee's staff. The meeting provided a beneficial update on licensee issues and plans to the resident staff and allowed direct interface with plant and corporate engineering personnel from both sites.

b. PC/M 138-294M, Modification of KLF Relays (37551)

This PC/M pertained to a modification to the loss-of-field relay associated with Unit 1 and Unit 2 EDGs. The modification revised the loss-of-field design within the relay to facilitate an EDG trip upon a loss of excitation when the EDG is synchronized to the offsite power system.

The inspector reviewed the engineering package documentation and observed that the modification had been classified as a minor design change. The modification package included a 10 CFR 50.59 screening evaluation to determine if a safety evaluation was required prior to implementing the modification. Based on the screening process, the modification was determined to be minor and a detailed safety evaluation was determined not required.

The inspector performed a detailed evaluation of the modification for Unit 2. The design change was reviewed and evaluated with respect to technical adequacy, compliance with FSAR commitments, and adequacy of 10 CFR 50.59 screening evaluations.

The loss-of-field relay provides protection for the EDGs upon the generator losing excitation. As described in the Unit 2 FSAR Section 8.3.1.1.2.k, in the absence of a SIAS, CIAS, or CSAS, or loss of offsite power, a loss of generator excitation results in a diesel generator lockout. The EDG loss-of-field relay is a W/ABB KLF relay which includes an undervoltage unit as part of the design. The approved modification was to jumper out the UV unit to provide for a generator lockout upon a loss of excitation without regard to the availability of voltage at the generator's terminals.

In 1994 while synchronized to the offsite power system, one of the St. Lucie EDGs lost generator excitation but the EDG did not trip since the UV unit within the loss-of-field relay had not actuated.

Since the EDG was still connected to the offsite power system, terminal voltage was present and therefore the loss-of-field relay did not actuate. Upon a loss of excitation, the generator operates as an induction generator with reactive power (VARs) flowing into the into the EDG. The design change was to essentially bypass the UV unit to provide for an EDG lockout on a loss of excitation without respect to terminal voltage. Based on the review of the design package, 10 CFR 50.59 screening evaluations, Unit 2 FSAR, and Unit 2 Technical Specifications, the inspector determined that the modification was acceptable, there was no change required to the FSAR or Technical Specifications, and there was not an unreviewed safety question.

The inspector observed the implementation of the modification associated with 2B EDG performed on March 22 via work order 95-0002, "Modify 2A and 2B EDG KLF Relays." At the time of the inspector's review, the licensee had implemented the modification to loss of field relay 40/964 located in the EDG control panel. The modification consisted of jumpering the UV trip unit within the relay. The inspector reviewed the in-progress NPWO documentation and verified that it reflected the status of the ongoing work. The inspector observed the post-modification testing on the relay which consisted of functional testing in accordance with procedure FPL protection and Control Quality test Instruction QTI-PS/PSL-2.09, Undervoltage Unit Test. Post-modification testing of the relay was documented in a loss-of-field relay test report. The recorded test results were reviewed by the inspector and confirmed that the relay test acceptance criteria was met. Test instruments were observed to be calibrated. No deficiencies were observed with respect to the engineering design package, implementation of the modification package, and functional testing of the relay. Following the completion of the relay functional testing, a surveillance test was performed on the EDG. The modification package and implementation of same were determined to be acceptable.

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.

At 9:30 p.m. on March 6, a fire was reported atop the Unit 1 pressurizer. The fire was limited to a 2" x 6" board which was being employed as a walkway by personnel monitoring pressurizer code safety valve performance. Personnel at the scene reported seeing small flames and smoke emanating from a board which rested, at one end, on a platform and, on the other end, on the upper head of the pressurizer. The board was removed from its location, passed down to personnel in the pressurizer cubicle, and sprayed with a fire extinguisher.

The board in question had been treated with flame retardant paint, per the licensee's fire protection program. The licensee found that the cause for the fire was the placement of the board in a position which gradually resulted in the compression of the insulation on the pressurizer head which allowed the board to come in contact with the metal. The high temperature of the pressurizer ultimately resulted in ignition and charring.

The inspector reviewed AP-0010434, Rev 30, "Plant Fire Protection Guidelines," and found that no violation of the procedure existed. The procedure provided general information and pointed out that judgement must be exercised in the performance of work. Step 8.2.8 of the procedure required that wood used in safety-related areas be treated with a flame retardant.

The inspector reviewed STAR 950247, which had been prepared to document and evaluate minor damage to two insulation panels as a result of the event. The engineering evaluation performed in response to the STAR considered the decrease in insulating capability of approximately two square feet of insulation which had been crushed due to board placement. The evaluation concluded that the original design assumptions regarding pressurizer insulation were valid, even if the insulating value of the damaged area was assumed to be zero. Acceptability of the damaged area from seismic and containment sump-blockage points of view were also considered. As a conservative action, the addition of redundant lacing wire was directed in the damaged area.

The inspector concluded that the issue was appropriately addressed and evaluated.

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. 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 that 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.

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.

No violations or deviations were identified.

7. Exit Interview

The inspection scope and findings were summarized on March 31, 1995, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection results listed below. Proprietary material is not contained in this report. Dissenting comments were not received from the licensee.

Type	Item Number	Status	Description
NCV	50-335/95-07-01	Closed	"Failure to Follow Shutdown Cooling Operating Procedures," paragraph 3.f
NCV	50-335/95-07-02	Closed	"Failure to Maintain Configuration Control of Unit 1 ECCS Area Ventilation Electrical Circuit," paragraph 4.a.1).
LER	50-335/93-009, 93-009-01	Closed	"Engineered Safety Features Actuation due to Spurious Subgroup Actuation Module Trip," paragraph 3.j.1).
LER	50-389/93-007, 93-007-01	Closed	"Manual Reactor Trip After the Simultaneous Dropping of Control Element Assemblies due to Equipment Failure," paragraph 3.j.2).

LER	50-335/94-003	Closed	"Automatic Reactor Trip Caused by Manipulation of the Main Generator Breaker Exciter Field Breaker due to Cognitive Personnel Error," paragraph 3.j.3).
LER	50-389/94-001	Closed	"Pressurizer Auxiliary Spray Out of Service Caused by a Mispositioned Isolation Valve Due to Personnel Error," paragraph 3.j.4).
LER	50-389/94-003	Closed	"Automatic Reactor Trip During Functional Testing of the Reactor Protective System Due to Bypass Miswiring During Original Construction," paragraph 3.j.5).
LER	50-389/94-004	Closed	"Plant Vent Wide Range Monitor Out of Service due to Personnel Error," paragraph 4.c.1).

8. Abbreviations, Acronyms, and Initialisms

ABB	ASEA Brown Boveri (company)
AEOD	Analysis and Evaluation of Operational Data, Office for
AFW	Auxiliary Feedwater
ANPS	Assistant Nuclear Plant Supervisor
AP	Administrative Procedure
ASME	American Society of Mechanical Engineers
ATTN	Attention
BA	Boric Acid
BAM	Boric Acid Makeup (tank etc.)
cc	Cubic Centimeter
CEA	Control Element Assembly
CFR	Code of Federal Regulations
CIAS	Containment Isolation Actuation Signal
CIS	Containment Isolation System
CRAC	Control Room Auxiliary Control (panel)
CS	Containment Spray (system)
CSAS	Containment Spray Actuation System
CVCS	Chemical & Volume Control System
DC	Direct Current
ECC	Estimated Critical Concentration
ECCS	Emergency Core Cooling System
ECP	Estimated Critical Position
EDG	Emergency Diesel Generator
ERDADS	Emergency Response Data Acquisition Display System
ESAS	Engineered Safeguards Actuation Signal

ESF	Engineered Safety Feature
ESFAS	Engineered Safety Feature Actuation System
F	Fahrenheit
FPL	The Florida Power & Light Company
FRG	Facility Review Group
FSAR	Final Safety Analysis Report
HPES	Human Performance Enhancement Systems
HPSI	High Pressure Safety Injection (system)
HVE	Heating and Ventilating Exhaust (fan, system, etc.)
HVS	Heating and Ventilating Supply (fan, system, etc.)
I&C	Instrumentation and Control
IN	[NRC] Information Notice
IR	[NRC] Inspection Report
JPE	(Juno Beach) Power Plant Engineering
JPN	(Juno Beach) Nuclear Engineering
KVAR	Reactive Load
KW	KiloWatt(s)
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LOI	Letter of Instruction
LPSI	Low Pressure Safety Injection (system)
LTOP	Low Temperature Overpressure Protection (system)
M&TE	Measuring & Test Equipment
MOV	Motor Operated Valve
MVAR	Reactive Load
NCV	NonCited Violation (of NRC requirements)
NPS	Nuclear Plant Supervisor
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NRR	NRC Office of Nuclear Reactor Regulation
ONOP	Off Normal Operating Procedure
OP	Operating Procedure
PC/M	Plant Change/Modification
PIG	Particulate-Iodine-Noble Gas Monitor
PM	Preventive Maintenance
PORV	Power Operated Relief Valve
psia	Pounds per square inch (absolute)
PSP	Physical Security Plan
PWO	Plant Work Order
QA	Quality Assurance
QI	Quality Instruction
QTI	Quality Test Instruction
RCA	Radiation Control Area
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
Rev	Revision
RII	Region II - Atlanta, Georgia (NRC)
rpm	Revolutions per Minute
RPS	Reactor Protection System
RTGB	Reactor Turbine Generator Board
RWT	Refueling Water Tank

SDC	Shut Down Cooling
SIAS	Safety Injection Actuation System
SNPO	Senior Nuclear Plant [unlicensed] Operator
SOER	Sequence of Events Recorder
SRO	Senior Reactor [licensed] Operator
St.	Saint
STAR	St. Lucie Action Request
TS	Technical Specification(s)
UV	Undervoltage
VAR	Reactive Load
VOTES	Valve Operation Test Evaluation System
WRGM	Wide Range Gas Monitor