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

Report Nos.: 50-335/91-04 and 50-389/91-04

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: January 23 - March 18, 1991

Inspectors: for R. Schin 4/12/91
S. A. Elrod, Senior Resident Inspector Date Signed

for R. Schin 4/12/91
M. A. Scott, Resident Inspector Date Signed

Frank Jape 4/12/91
F. Jape, Section Chief Date Signed

Approved By: R. V. Crlenjak 4/15/91
R. V. Crlenjak, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection was conducted onsite in the areas of plant operations review, maintenance observations, surveillance observations, review of special reports, review of nonroutine events, and followup of previous inspection findings.

Results:

The Unit 1 shutdown to test control element assemblies (CEAs) was well controlled. Unit 1 also had three events that were well handled. They resulted in licensee event reports (LERs) and a special emergency diesel generator (EDG) report. Certain maintenance and surveillance activities resulted in challenges to the operators or safety systems. These included automatic initiation of auxiliary feedwater (AFW) during operation, dropping of a CEA during shutdown testing, and four of eight reactor trip breakers opening simultaneously.

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Operator responses to plant events were well handled.

Within the areas inspected, the following non-cited violations (NCVs) were identified.

NCV 335,389/91-04-01, Specification of Improper Thread Sealant in Safety-related Applications, paragraph 2a.

NCV 335,389/91-04-02, Inadequate Control of Post-Maintenance Tests, paragraph 4.

NCV 335/91-04-03, Failure to restore 1B Component Cooling Water Pump Missile Shield After Maintenance, paragraph 2a.

NCV 389/91-04-03, Failure to Scope Change a Nuclear Plant Work Order Controlled Test of 2B EDG Field Control Circuits, paragraph 3.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   D. Sager, St. Lucie Site Vice President
   * G. Boissy, Plant Manager
   J. Barrow, Fire Prevention Coordinator
   * C. Burton, Operations Superintendent
   R. Church, Independent Safety Engineering Group Chairman
   * H. Buchanan, Health Physics Supervisor
   * D. Culpepper, Site Engineering Supervisor
   * R. Dawson, Maintenance Superintendent
   * R. Englmeier, Site Quality Manager
   * R. Frechette, Chemistry Supervisor
   C. Leppla, I&C Supervisor
   L. McLaughlin, Plant licensing Superintendent
   * A. Menocal, Mechanical Maintenance Supervisor
   * D. Oliver, Material Management Superintendent
   L. Rogers, Electrical Maintenance Supervisor
   N. Roos, Services Manager
   C. Scott, Outage Management Supervisor
   * D. West, Technical Staff Supervisor
   J. West, Operations Supervisor
   W. White, Security Supervisor
   G. Wood, Reliability and Support Supervisor
   * E. Wunderlich, Reactor Engineering Supervisor

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

   NRC Employees

   * S. Elrod, Senior Resident Inspector
   * M. Scott, Resident Inspector
   * R. Marston, Radiation Specialist
   F. Jape, Section Chief

   * Attended exit interview

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

2. Review of Plant Operations (71707)

   Unit 1 began the inspection period at power but shut down for one day on January 28 for NRC-required full length exercising of the CEAs. The unit ended the inspection period in day 48 of power operation.

Unit 2 began and ended the inspection period at power - day 102 of power operation.

During this period, the licensee made several significant personnel assignments. Mr. C. Burton was appointed Operations Superintendent, Mr. J. West was appointed Operations Supervisor, and Mr. A. Menocal was appointed Mechanical Maintenance Supervisor.

a. Plant Tours

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 to be adequate.

The inspectors routinely conducted partial walkdowns of ESF, ECCS and support systems. Valve, breaker, and switch lineups and equipment conditions were randomly verified both locally and in the control room. The following accessible-area ESF system walkdowns were made to verify that system lineups were in accordance with licensee requirements for operability and equipment material conditions were satisfactory: Unit 1 and 2 CCW platforms, Unit 1 SFP, 1B EDG, Unit 1 and 2 cable spreading rooms, and Unit 1 and 2 battery rooms.

During the walkdown of the Unit 2 CCW platform, the 2B CCW heat exchanger was found leaking from the mechanical joint between the shell and the ICW inlet channel head. The minor 24-drop-per-minute leak posed no threat to unit operation. The weld adjacent to this joint was of recent interest due to weld problems discussed in IRs 335,389/90-30 and 90-31 (LER close out). Due to those considerations, the normal leak repair option of retorquing the mechanical joint fasteners was not performed. NPWO 3803/62 was generated to repair the joint during the next refueling outage. This long term planning was acceptable. By the end of February, the leakage had stopped on its own.

During a walkdown of the Unit 1 CCW platform on February 28, two of six connector plates were found missing from one end of an I-beam supporting the 1B CCW pump missile shield overhead. A plastic half-gallon jug of lubricating oil labeled with a marking pen was also found stored in the web of a side beam. The licensee immediately removed the oil, manufactured new plates, and restored the missile shield to its design. The other missile shields were examined and found correct. The licensee determined that the connection plates had been removed during missile shield disassembly to support NPWO 3240/61 between June 13 and 26, 1988. Licensee engineering evaluation of the as-found missile shield operability showed that the missing plates degraded the missile shield somewhat but it continued to provide design protection levels.

Licensee review of several maintenance procedures dealing with equipment protected by missile shields showed that the procedures did not clearly restore missile shields to their design following removal for equipment maintenance. This is contrary to TS 6.8.1 which requires that procedures be established and implemented to cover activities recommended in Appendix A of Regulatory Guide 1.33. The licensee subsequently revised these procedures to include the proper requirements and independent verification of completed action.

This violation is not being cited because the criteria cited in section V.G.1 of the NRC Enforcement Policy were satisfied. This item is identified as NCV 335/91-04-03, Failure to Restore the 1B CCW Pump Missile Shield After Maintenance.

During a walkdown, the 2B battery rack plastic rail insulation was found cracking into large flakes. This unusual condition was pointed out to the licensee management for evaluation. The licensee plans to replace the side rail covers during the next refueling outage and the bottom rail covers whenever the batteries are next removed from the racks.

On February 6, the thermal overload/bypass switch for Unit 2 HCV 3627, located in MCC 2A6, was found by the inspector in the maintenance-test position vice the TS-required overload bypass position. This placed Unit 2 into a 72-hour LCO action statement per TS 3.4.5.2, ECCS Subsystems - T avg greater than or equal to 325 F. Checking switch position was an 18 month surveillance per TS 4.8.4.a. but the position was routinely checked daily by the operators. This switch appeared to have been mispositioned when the MCC was masked for painting earlier that day. An operator immediately restored the correct switch position. All other switches were found to be correctly positioned.

During a walkdown of 2B EDG, a new black thread sealant was observed applied to pipe threads on the nipple attaching the starting air tank relief valves to the starting air tanks, an ambient temperature application. The sealant container indicated that the sealant, named PRI-102N, should be stored below 20 degrees Fahrenheit and that the use temperature range was 150 - 1000 degrees Fahrenheit. Review of storage requirements showed that the licensee did not implement these directions. The vendor informed the licensee that the storage temperature requirements were to extend shelf life, that in the 80 - 100 degrees Fahrenheit range, the material would at least provide thread lubrication for the threaded joint, and that the material would not harm the stainless steel fittings. The inspector found the licensee's understanding and control of this sealant to be inadequate. The threaded nipples were replaced several times before joint leaks were stopped, however these minor air leaks did not make the EDGs inoperable.

Subsequent licensee review found that the planners were improperly specifying this sealant because AP 0010507, Rev 2, Control of Chemicals and Materials for Maintenance of Plant Systems, did not identify the limiting applications of several compounds and also did not clearly identify which systems were meant by "RCS" or "Fuel Pool" or "Secondary". This is contrary to TS 6.8.1 which requires that procedures be established and implemented covering activities recommended in Appendix A of Regulatory Guide 1.33. The Regulatory Guide recommends written procedures for limiting the concentration of agents that may cause corrosive attack or fouling of heat transfer surfaces. It also recommends procedures for maintenance that can affect the performance of safety-related equipment. AP 0010507, Rev 2, Control of Chemicals and Materials for Maintenance of Plant Systems, was the licensee's vehicle for ensuring appropriate use of chemicals and materials in maintenance. These items were corrected.

This violation is not being cited because the criteria cited in section V.G.1 of the NRC Enforcement Policy were satisfied. This item is identified as NCV 335,389/91-04-01, Specification of Improper Thread Sealant in Safety-Related Applications.

b. Plant Operations Review

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 assure 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.

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

1-1-107 MV 14-3 Unit 1 CCW Pump Suction Cross Tie, 1-1-129 1A2 Circulation Pump and Water Box,

1-2-34 TCB 5 Unit 1 Reactor Trip Breaker, and

2-2-108 2B EDG Replace Starting Air Pipe Nipples.

The inspectors reviewed quality assurance activities and findings concerning control room operations to determine if the objectives were being met. The following activities were reviewed:

Quality Assurance Audit Performance Monitoring Report - November QSL-OPS-90-780, of December 20, 1990;

Quality Assurance Audit QSL-OPS-90-773, Refueling Sequencing Activities, of December 20, 1990;

Quality Assurance Audit QSL-OPS-90-766, Class 1E 4KV Breaker and Cubicle Modification, of December 28, 1990; and

Quality Assurance Audit Performance Monitoring Report - October, QSL-OPS-90-772, of November 16, 1990.

These audit reports contained two findings that were minor. The overall scope of the activities reviewed and observed appeared to be extensive.

Unit 1 was shut down to hot standby, Mode 3, on January 28 to full stroke exercise the CEAs. This was the second time this was accomplished on this unit. The exercise was last accomplished on October 27, 1990, as discussed in IR 335,389/90-30.

The applicable procedures in effect for the shutdown, required mode change testing, and CEA exercise were:

OP 1-0030128, Rev 7, Reactor Shutdown to Hot Standby;

OP 1-0030125, Rev 22, Turbine Shutdown - Full Load to Zero Load;

OP 1-0030150, Rev 43, Secondary Plant Operational Checks & Tests; and

LOI-0-40, Rev 0, Testing of Original Design Type #1 Control Element Assembly.

The shutdown, Unit 1's 217th, was controlled and relatively uneventful. At the point of switching from the main feedwater regulating valves to the 15-percent capacity feedwater regulating valves, the A train main feedwater regulating valve was found to leak by when closed. Its associated block valve was then shut to limit main feed flow to the A SG. Several feedwater heater level control valves required some monitoring by operators. CEA number 45 had some mid-travel indication problems during CEA insertion. These were minor problems.

During CEA exercising, with Unit 1 shut down and stable, a reactor operator's personnel error during non-related simultaneous testing generated an inadvertent reactor trip signal. The operator was performing a loss-of-turbine trip test, OP 1-1400054, when he turned a wrong switch, completing the reactor trip logic. The "A" channel high-startup-rate subchannel was out of service and had been previously placed in the tripped position. The operator reached for a "B" channel linear power trip test switch but instead turned the "B" channel high-startup-rate test switch. This satisfied the trip logic. The TCBs opened as designed, dropping the one CEA. Equipment functioned properly during this event. The only result of the error was that the CEA being exercised was inserted into the core to join the other fully-inserted CEAs. The licensee made the proper event notifications. The licensee also involved their human factors personnel in the event review preceding a written LER.

During after-shutdown inspections of the Unit 1 containment, the licensee found boric acid on the lagging of RCS loop check valve V 3247. Site personnel removed the lagging, inspected the valve, and found that the disk-hinge-pin end caps were leaking one-half to one quart of water per hour.

Based on the following considerations and prior experience, the licensee deferred repair but left the lagging off the valve.

FPL valve drawing 8770-1216 (Atwood & Morrill drawing 21152-H), showed that the valve components were all constructed of corrosion resistant material, which meant that the boric acid would not deteriorate the valve.

Attempts to tighten the hinge pin cap fasteners would have probably aggravated the leaks.

Repair of the valve would have required plant shutdown to cold conditions and partial drainage of the RCS.

The present leakage would probably not increase greatly and was well below the TS-allowed leak rate.

Leaving the lagging off the valve would facilitate future inspections. It also would allow the leakage to flow immediately to floor drains instead of potentially running down the lagging interior to drip on previously unaffected components.

After the CEA exercise, the licensee restarted Unit 1 on January 29. The turbine output breaker was closed at 3:12 a.m. Later checks of containment radioactive particulate and gas levels indicated no upward trending.

At 100 percent power on January 30, the 1B heater drain pump discharge valve failed closed, which tripped the heater drain pump. Operators reduced reactor power fast enough to prevent a reactor trip and stabilized the plant at 93 percent power.

Evaluation of the 1B heater drain pump discharge valve's internal trim indicated that the lower guide/skirt had eroded to the point that valve internals caught on the inside of the valve. The resultant stem forces caused the valve stem to snap outside the valve body. No valve parts escaped the valve body. The "B" train heater drain valve was repaired in conjunction with vendor and engineering input. The valve had not been inspected since about 1982 when the valve trim was modified per a PCM. The valve was placed on an inspection schedule. Importantly, the 1A valve trim did not have a skirt to catch, had been inspected in 1990, and was scheduled for inspection at the next refueling outage. The mechanical maintenance department generated a root cause and corrective action package for future reference.

While performing the Unit 1 monthly AFAS D channel surveillance test, I&C technicians found that the 1-3 initiation relay light was not lit. The concern was that there may have been no power in one of two paths to this relay. The surveillance was stopped and NPWO 6151/61 was written to investigate the no light/relay concern.

NPWO 6151/61 did not invoke procedure AP 0010142, Unit Reliability - Manipulation of Sensitive Systems, that would have caused more shop preparation time and maintenance management pre-implementation review. The NPWO work was performed by the technicians who had been performing the surveillance and who had initially discovered the problem. During troubleshooting, the D channel was placed in bypass, which bypassed the actuation logic circuits but not the initiation circuits where the troubleshooting was being performed. Troubleshooting under the NPWO opened one of two power paths to the 1-3 relay in an attempt to locate a bad screw-type fuse (three in each of two paths). The technicians inadvertently unscrewed a fuse in the other power path, which deenergized the 1-3 relay. Once the 1-3 relay was deenergized, the 1C AFW pump circuitry was actuated and the pump started. The operators immediately realized that the pump had started, had the technicians re-install the fuse, and then stopped the pump. No injection of CST water occurred. The licensee made notifications per 10 CFR 50.73 and was preparing an LER. Site management has increased the site sensitivity to the use of the sensitive systems procedure.

On February 12, the licensee performed the quarterly stroke test on Unit 1 MV 09-11, one of two AFW injection valves available for the 1C AFW pump. It passed the test, requiring a few seconds longer to stroke than the previous test but within the acceptance criteria of AP1-0010125A, Rev 18, Surveillance Data Sheets, Data Sheet 8A. The valve had ast been MOVATS tested in March 1990.

On February 15, the licensee was making cold weather preparations for an impending cold front with potentially subfreezing conditions. On this day, the systems engineer toured the steam trestle space containing MV 09-11. On February 16, a Unit 1 operator checked shut MV 09-11 by turning the control room hand switch to closed with the valve already in the closed position. This check shut was to prevent potential valve leakage due to changes in valve clearances or valve position differences caused by ambient temperature changes (cooling). Remotely checking the valve shut was an acceptable operation with this valve because the actuator's torque switch should prevent overtorque. At about noon on February 17, a non-licensed operator found the valve's handwheel, with the thrust bearing plate attached, laying on the floor below the valve. The plate was normally bolted to the valve actuator by four 5/16 inch bolts. The bolts had been broken by the stem force resulting from valve overtorque. Both the actuator stem and valve stem had been bent, and the actuator stem was completely disengaged from the actuator. The stem overtravel distance taken up by the bending was approximately 1-1/4 inch, equating to about 20 to 25 seconds of actuator operation. In summary, after being checked shut, MV 09-11 would not have re-opened electrically or manually. The licensee made the appropriate notifications in accordance with 10CFR50.73 requirements and is generating an LER on the event. The impact of the valve failure was that the 1C AFW pump could pump only to the 1B steam generator. Each 100-percent-capacity motor-driven pump could pump to both steam generators if required.

The licensee removed, repaired, and tested the MV 09-11 actuator utilizing NPWO 5239/61 and procedure MP 0940075, Rev 1, Maintenance and Repair of Limitorque Valve Actuators Type SMB 000. A separate NPWO replaced damaged valve trim parts. The licensee did not find a root cause.

Actuator disassembly revealed no cause. The torque switch was bench tested satisfactorily. The spring pack was in good shape and was not hydraulically locked.

Nothing found in the valve itself was implicated in the failure.

The 120 V DC contactor for the actuator was examined and tested. Visual and manual inspection revealed free travel, no contact corrosion, and no excessive contact pitting. Contactor actuation timing was about 20 ms (50 ms usually indicates problems).

The rebuilt valve and actuator with its unadjusted torque switch were re-assembled and MOVATS tested. Testing indicated satisfactory operation and did not pinpoint a root cause for the dysfunction.

The licensee discussed the problem with the actuator vendor who did not offer any suggestions.

The valve was returned to service on February 18. The licensee replaced the torque switch on February 21 and, when it becomes available, will replace the contactor as a conservative measure. The contactor had a July 1991, delivery date. Retesting after each component replacement was again satisfactory. A caution tag was installed on the control room hand switch for MV 09-11 stating that electrical personnel must be at the valve during routine operation. This conservative measure will remain in effect until the new contactor is installed.

On February 19 at 10:30 am, with Unit 1 at 100 percent power, the 1B CCW pump tripped for no apparent reason. Operations personnel changed the valve lineup and placed the 1C swing CCW pump into operation within a half hour in accordance with ONOP 1-0310030, Rev 1, Component Cooling Water - Off Normal Operation. During the transition, the unit was in a 72 hour LCO.

Root cause investigation of the pump trip revealed an unusual relay location. The CCW pump motor breaker cubicle door had a number of relay devices installed on it such that there was insufficient room for the overcurrent relay. That relay had been installed on the door of the adjacent breaker cubicle, which served the B train HPSI pump. This condition existed on the A train also. Though the overcurrent relays were marked to identify which cubicle they protected, the identification markings were small. Nothing on the cubicles themselves identified the relay function. The historical information regarding these relays resided in the electrical group's common knowledge. The sensitive system marking program re-instituted several months ago did not add markings to this relay. NPWO 4405/61 administratively controlled the installation of a ground test device in the 1B HPSI pump breaker cubicle. The licensee was able to establish that, when electricians subsequently reinstalled the HPSI pump breaker, the door with the attached overcurrent relay was not open quite far enough and the overcurrent relay was struck hard enough by the breaker front to trip the 1B CCW pump.

Initial investigation found that the relay was seismically qualified. Corrective actions concerning this condition will be addressed in IR 335,389/91-09.

On February 20, at 10:37 p.m., with Unit 1 at 85 percent power and with the 1B CCW pump out of service, the 1C CCW pump tripped. At least six annunciators alarmed in the control room. Operators confirmed that it was a pump trip and understood that the cause was probably electrical. Attempted restart of the 1C pump produced sparks from the motor shroud. Operators immediately initiated plant-condition-oriented corrective action and cross tied the CCW headers by 10:40 p.m. This configuration provided cooling flow to both A and B train components using the 1A CCW pump and both A and B CCW heat exchangers. By 11:15 p.m., CCW flow to non-essential loads was isolated to increase flow to safety-related loads. CCW temperature was monitored to ensure FSAR-specified cooling was occurring. With the failure to restart the 1C pump, the licensee entered an action statement per TS 3.7.3. The licensee expedited returning the 1B CCW pump to service by 5:30 a.m., then exited the TS action statement. Operations was considering possible procedure changes to address operator actions when only one pump is available. The 1C CCW pump motor was removed and shipped for rewind due to an apparently failed phase. The vendor has also been tasked with root cause identification. Repair time was to be approximately four weeks.

On February 25, the Unit 2 reactor protection system channel B main 15 ampere fuse blew and tripped open four of the eight reactor trip circuit breakers. Since no other protection channel inputs were degraded, this did not trip the unit. The operators coordinated well the plant staff investigation and the recovery. RPS channel B was repowered and restored to service in two hours. The cause was found to be a cooling fan flow-indicating light bulb being changed. It had no inline resistance or fuse and was powered directly from the electrical supply. The unusual bulb and socket design did not inhibit an arc across the bulb base and evidence of such an arc was plainly visible. The licensee was coordinating a potential design change with the NSSS vendor.

c. Technical Specification Compliance

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 and complete (except as noted above), and included the most recent revisions.

d. Physical Protection

The inspectors verified by observation during routine activities that security program plans were being implemented as evidenced by: proper display of picture badges; searching of packages and personnel at the plant entrance; and vital area portals being locked and alarmed.

Aside from the operator error during the Unit 1 Turbine trip test, operator performance was good. Several Unit 1 events were well handled by the staff.

3. Surveillance Observation (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 surveillance tests observed and problems encountered are discussed below.

During the performance of 2B EDG governor oil PM starts, the electrical maintenance staff noted that the diesel would accelerate to its normal start rpm but would only load to about 2000 KW. The 2B2 hydraulic governor control limit switch had failed. The licensee generated special report L-91-55 (10 CFR 50.36) of February 15, 1991.

NPWO 4407/62 controlled the 2B2 diesel governor limit switch replacement and tested the functionality of the switch during a normal surveillance run per OP 2-2200050, Rev 27, Emergency Diesel Generator Periodic Test and General Operating Instructions. The NPWO contained specific FRG-approved instructions for post-repair switch testing. These were utilized conjunctively with the surveillance test. With the engineer present, a non-licensed operator performed the test at the diesel's local panel. The testing proved that the new switch was operating satisfactorily. This was the third failure of the 2B EDG in its last 100 starts.

During this testing, the licensee noted that the associated 125 V ground annunciator would temporarily illuminate and then clear when the EDG was started. Investigation revealed a partial ground on the 2B generator field control circuit boards. Troubleshooting indicated that the ground was not degrading and did not affect adequate generator field strength or required EDG output. The problem was discussed with FRG members. The FRG agreed that the circuits would operate as desired. Since the new board required extensive calibration and would not be available for the existing time window, a satisfactory surveillance was performed. The EDG was declared back in service on January 18.

The electrical department and the technical support staff developed a repair game plan and an extensive post-repair test procedure for the repair and testing of the 2B EDG field control circuits at its next scheduled surveillance. FRG-approved NPWO 5767/62 controlled the repairs that removed the ground fault and also contained the post-repair test procedure to use in conjunction with OP 2-2200050 identified above.

The repaired 2B EDG was tested on January 30 with electrical department and technical support personnel at the EDG. During this test, control room operators ran the test instead of personnel at the EDG local panel. The operations personnel made wording revisions to the electrical department NPWO and performed the test slightly differently than originally approved. They did not have the electrical staff submit the revisions for FRG approval as a scope change per section 8.6 of AP 0010432, Rev 48, Nuclear Plant Work Orders. This is contrary to TS 6.8.1 which requires that procedures be established and implemented covering activities recommended in Appendix A of Regulatory Guide 1.33. The Regulatory Guide recommends written procedures for maintenance that can affect the performance of safety-related equipment. Procedure AP 0010432, Nuclear Plant Work Orders, specified that scope changes occurred when work was required outside the scope of the approved NPWO work description and that scope changes to NPWOs required the same level of approval as the original document.

The 2B EDG NPWO changes did not reduce test stringency. One change increased the initial EDG loading to reduce the likelihood of a reverse power trip. The other noteworthy change made the heat run EDG loading consistent with the surveillance procedure OP 2-2200050 loading value. The actual surveillance test was completed satisfactorily and overall EDG operation was excellent.

When apprised that the NPWO had been inappropriately changed by the operations staff, the licensee completed a NPWO scope change and obtained FRG re-approval. The appropriate personnel were counselled by plant management on the above AP requirements. The licensee was discussing using a separate procedure for testing in lieu of a NPWO addendum in the future.

This licensee-identified violation is not being cited because of the criteria cited in section V.G.1 of the NRC Enforcement Policy were satisfied. This item is identified as NCV 389/91-04-03, Failure to Scope Change a NPWO Controlled Test of 2B EDG Field Control Circuits.

Testing per OP 2-1400054, Rev 2, Reactor Protection System - Loss of Turbine Hydraulic Fluid Pressure Low, was performed on February 1. The inspector observed the satisfactory completion of this surveillance. Good communication was exhibited during its performance.

During this inspection period, electrical maintenance performed lubrication PMs on Unit 1 MV 14-3 and 14-4 actuators. The valves open to the suction of the 1C CCW pump from the A and B train CCW return lines. NPWOs 4351/61 and 4352/61, respectively, controlled the PMs and required cycling of the valves for functional testing. AP 1-0010125A, Rev 18, Surveillance Data Sheets, sheet #8B, provided acceptable valve stroke times consistent with ASME Code Section XI. Cycling and stroke times on these valves were acceptable.

These valves were of interest for several reasons. NRC Information Notice 90-73, Corrosion of Valve-to-Torque-Tube Keys in Spray Pond Cross Connect Valves, discussed problems with Pratt valves in submerged applications. Currently, the licensee has this notice under review for possible action. At this site, two such valves are used in a submerged application. A number of Pratt valves such as these, which are not submerged, are used throughout both units. They are exposed to the weather and a salt-laden environment in many instances. Previously, two similar air operated non-submerged Pratt valves froze in place while in a non-safety-related, nearly static, temperature control application on the open blowdown heat exchangers. Due to heavy corrosion, the stem bushings welded to the valve body. The bushings were below the lip of the valve's side such that standing moisture could exist. MV 14-3 and 14-4 do not have the same configuration but could experience salt intrusion between the stem and packing cap or strongback. At the time of the PMs, both MVs exhibited no corrosion at this joint.

On March 4, the inspectors witnessed the Unit 2 MSIV and MFIV periodic tests per OP 2-0810050, Rev 14, Main Steam/Feedwater Isolation Valve Periodic Test. Concurrently, MFIV PM 20-M-0018, Rev 22, was observed on HCV 09-2A using NPWO 2072. This PM performs hydraulic system maintenance such as changing the oil filter. Test and PM preparation, coordination, and control were excellent.

During this observation, several small instrument air leaks were observed, The persons participating in the surveillance thought others would report these leaks. No one did. The maintenance supervision, when informed, took corrective action to have the systems re-examined, leaks addressed, and the staff counseled concerning management expectations.

Aside from the NCV discussed, overall surveillance activities were well executed.

4. Maintenance Observation (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 assure that priority was assigned to safety-related equipment. Portions of the following maintenance activities were observed:

NPWO 5487/62 on Unit 2 administratively controlled repacking of MV 08-19B, a main steam atmospheric dump valve. Repacking was necessary to prevent steam damage from a minor packing leak. The valve was satisfactorily repacked in accordance with procedure GMP M-0043, Rev 7, Valve Repacking.

NPWO 5756/62 on Unit 2 administratively controlled valve actuator testing of MV 08-19B. The valve parameters were acceptable per the testing. The above repacking, the cause for the testing, had caused a slight and expected reduction in the driving torque on the valve.

NPWO 7766/61 on Unit 1 administratively controlled the replacement of FT 09-2C, 1C AFW pump flow transmitter. The technicians utilized vendor instructions to accomplish the change-out. The change-out was based on the information provided in NRC Bulletin 90-01, Loss of Fill-Oil in Transmitters Manufactured by Rosemount, that discussed transmitter internal oil leaks that may cause dysfunction. The replaced FT had not shown any functional abnormalities during its last monthly calibration. Parts and "O" ring grease, a shelf life item, used during the work were well controlled. The FT was tested in accordance with good shop practice and procedure I&C 1400064F, Rev 15, Installed Plant Instruments (Flow), Appendix "C".

NPWO 5716/61 on Unit 1 administratively controlled the repair of TCB number 5. During an RPS logic matrix test, this TCB failed to close (remained in a safe position). The electrical shop replaced an "X" type anti-motoring relay with a new one having supposedly appropriate credentials/pedigree. That action was supposed to repair the breaker, however the breaker still would not close.

The day shift personnel that had replaced the relay did not normally work with these GE Model AK 2-25 breakers. The non-licensed operator that had placed the TCB into test position for the day crew had just transferred to Unit 1 for refamiliarization. A spring loaded sleeve around the racking shaft had hung up on the shaft's drive pin. The pins receive the notches of the speed wrench that slips over the shaft end when racking the breaker. When the sleeve is normally driven in around the shaft during racking (in or out), the breaker is in a tripped state due to the sleeve's depressed position. The non-licensed operator and day shift electrical personnel did not remember the effect of the sleeve hanging up on the drive pin.

Peak shift (or second shift) normally did repairs and PMs on these particular breakers. When peak shift came on duty, they immediately mentioned the sleeve hanging up as an option for the dysfunction and proved that to be the case. The breaker tested satisfactorily after the sleeve was positioned properly.

During the TCB 5 repair, a new engineering effort became apparent. Material engineers had recently reclassified certain types of repair parts with new procurement levels and requirements. In the case of this replacement "X" relay, it had been changed from a commercial procurement level to a quality classification that dovetailed with electrical class E-1 and included vendor-provided documentation. This particular relay was not safety-related by function since it closed the breaker. The reclassification for the relay was a conservative action.

The initial replacement relay drawn from stores had not been reclassified under the new program, but existed in the stock system under the same vendor-provided part number as the upgraded relays. Prior to returning the breaker to service, the electrical department realized this and located the correct, upgraded relay purchased from the same vendor who built the breaker. The new or second relay did not fit the mounting bracket on the breaker. The new relay was physically different from both the original and initial replacement relays, which were twins. A new bracket had to be installed with the new relay. The licensee corrected their stock system part identification for the relay. The licensee expected more procurement upgrade program implementation problems of this type.

NPWO 1920/61 administratively controlled work on the lube water strainer SS-21-3A1 for the Unit 1 ICW pumps. Multiple strainer parts were replaced and cleaned, and the strainer was returned to service on February 8. On February 11, three days after the equipment was returned to service, the QI 11 post-maintenance test form, part of the NPWO package, was brought to the Unit 1 control room for operations department performance.

The mechanical maintenance group used a procedure form from QI 11-2 to track test requirements and completion for components being repaired. The required testing was a visual inspection of the component during operation with no evidence of leakage. Subsequent review showed that when operations valved the strainer back into service, the non-licensed operator who would have normally performed this type of test actually observed strainer operation and reported its condition back to the control room. The results of the observation were not formally documented on the QI 11 form that arrived in the control room three days later. The Journeymans' Work Report pages appended to the NPWO detailed that operations personnel were on hand to verify that the strainer backflush feature worked properly. Procedure 1-M-0018, Rev 19, Mechanical Maintenance Safety-Related Preventive Maintenance Program, Appendix A, had been completed verifying that the mechanic observed the proper backflush cycle and that there was no external leakage observed. This duplicated the QI 11 form requirements but was documented by the wrong department. On February 11, the NRC inspector also observed that there was no strainer leakage. In summary, it was apparent that the specified testing, the operations department observation of satisfactory strainer operation, had occurred but the operator had not been formally tasked to do this as a test function nor had the test been formally documented. This was thought to have been an isolated case.

This is contrary to TS 6.8.1 which requires that procedures be established and implemented covering test activities of safety related equipment. The TS and the FSAR identified the ICW system as safety related. The applicable procedure involved, QI 11-PR/PSL-2, Rev 20, Mechanical Test Control, required that testing of the component be completed prior to returning it to service. Procedure sections 5.7, 5.8, and 5.16, step 3, addressed return to service requirements.

This situation was mitigated by the informal operations actions when valving-in the strainer and the mechanics' documentation of their actions. Licensee review identified that the specified post-maintenance test may not actually be a factor in determining operability. The coordination process was modified to provide operations control of post maintenance testing.

This licensee-identified violation is not being cited because the criteria cited in Section V.G.1 of the NRC Enforcement Policy were satisfied. This item is identified as NCV 335,389/91-04-02, Failure to Follow Post Maintenance Test Control Procedures.

Aside from the concerns addressed in the NCVs and the error in AFAS maintenance, maintenance activities were well controlled.

5. Review of Periodic and Special Reports (90713)

Paragraph 3 discussed a special report issued by the licensee on the 2B2 governor control switch failure. The report properly identified the 2B EDG failure (TS 4.8.1.1.3) and identified satisfactory corrective actions.

6. Onsite Followup of Events (93702)

Nonroutine plant events were reviewed to determine the need for further or continued NRC response, to determine whether corrective actions appeared appropriate, and to determine that TS were being met and that the public health and safety received primary consideration. Potential generic impact and trend detection were also considered. Section 2 of this report covered several events at the plant, as follows:

Inadvertent Unit 1 trip with 1 CEA withdrawn,

MV 09-11 failure on Unit 1,

1B CCW pump trip on Unit 1,

1C CCW pump motor failure on Unit 1, and

Inadvertent AFAS partial actuation on Unit 1.

7. Followup (92701)

a. Followup of Unresolved Items

1) (Closed - Unit 1) URI 335/89-02-02, Upgrade of EOP Training for Operators.

This item addressed the failure of the licensed operator training program to address the unique identification of Regulatory Guide 1.97 instrumentation. Although the instrumentation in the control room was appropriately identified, the simulator instrumentation was not identified and the EOPs did not specifically reference this unique identification or its use. A walkdown of the simulator facility accomplished during the EDSFI (NRC IR 335,389/91-03) demonstrated that the regulatory guide instrumentation had been appropriately identified in the simulator. A review of selected EOP procedures and the appropriate simulator lesson plan, Accident Instrumentation, Rev 0, demonstrated that the training program had effectively addressed this issue. Based on the above, this item is closed.

2) (Closed - Units 1 and 2) URI 335,389/88-30-02, Correlation Between Air and Steam on Safety Relief Valve Setpoints.

At the time this unresolved item was issued, it appeared that bench testing of safety relief valves did not include the necessary adjustment for setting the setpoint cold. Since that time, the licensee has completed an engineering study to verify the correlation between cold and actual operating temperature setpoint settings. The engineering study contains several recommendations which are currently under review by the licensee. The procedure for setting the setpoint includes a 30 psi adjustment to account for the difference between cold and hot setpoint.

A refueling outage is currently scheduled for Fall of 1991. The setpoints of the code safety valves are to be checked during this outage. Results of this surveillance activity will be reviewed to determine if the correlation is adequate. This unresolved item is closed.

b. Followup of Previously Identified Items

(Closed - Units 1 & 2) OPN 335,389/88-29-01, Inplant Diesel Instrumentation Calibration.

This item was initiated to track inspector review of the calibration status of local instruments used in operating EDGs. The specific surveillance observed involved 1A EDG. Local temperature indicators were of particular interest. Since that time, all the applicable operating and maintenance procedures have been revised so this followup was more comprehensive than the initial item statement.

The inspector reviewed the following documents:

MP 0990060, Rev 4, Calibration Check of Installed Metering Equipment;

MP 0970025, Rev 5, 18 Month Calibration of Emergency Diesel Generators Wattmeters;

OP 1-2200050, Rev 51, Emergency Diesel Generator Periodic Test and General Operating Instructions;

OP 2-2200050, Rev 27, Emergency Diesel Generator Periodic Test and General Operating Instructions;

Unit 1 and Unit 2 Instrument Lists regarding EDGs;

PWO 0140/61, completed 3/1/90, Unit 1 FYP 0159;

PWO 8203/61, completed 3/10/90, Unit 1 FYP 0307;

PWO 7452/61, completed 9/26/89, Unit 1 MTSI-044;

PWO 8195/62, Unit 2 FYP 0595, FYP 0594;

PWO 8169/62, completed 10/24/90, Unit 2, FYP 0569B;

PWO 8170/62, completed 10/25/90, Unit 2, FYP 0570;

PWO 8173/62, Unit 2 FYP 0573;

PWO 8172/62, Unit 2 FYP 0575;

PWO 7966/62, completed 5/4/90; and

PWO 6489/62, completed 8/8/89.

This review concluded that the Unit 1 and Unit 2 EDG electrical meters and instruments were identified on lists for periodic calibration. All the Unit 1 EDG electrical meters and instruments had been calibrated. All the Unit 2 EDG electrical meters and those instruments that were of operational importance had been calibrated. The licensee was actively enhancing the periodic calibration list for the Unit 2 EDGs. The operating procedures were satisfactory but had some human factors weaknesses in instrument identification. The licensee subsequently reissued the operating procedures with significantly enhanced instrument identification. This item is closed.

8. Followup of Corrective Actions for Violations and Deviations (92702)

(Closed - Unit 1) VIO 335/89-02-01, Failure to Calibrate Six Regulatory Guide 1.97 Instruments.

This item addressed six instrumentation loops which were not calibrated as required by Regulatory Guide 1.97. These items were not appropriately entered into a tracking program.

The corrective actions indicated in the licensee response to the NRC, dated April 3, 1989, have been completed. The identified instrumentation was entered into the Planned Maintenance Program and calibrated. The six instruments and loops referenced in the report were entered into the Planned Maintenance Program as demonstrated by review of the Nuclear Job Planning System Planned Maintenance Schedule, dated February 21, 1991. The individual instrument/loops were calibrated by the licensee when identified by the NRC inspection team as discussed in the originating report, IR 335,389/89-02. Licensee action to correct the identified issue and prevent recurrence was adequate. This item is closed.

9. Exit Interview (30703)

The inspection scope and findings were summarized on March 29, 1991, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection findings listed below. Proprietary material is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Status		Description and Reference
335,389/91-04-01	Closed	NCV -	Specification of Improper Thread Sealant in Safety-Related Applications, paragraph 2a.
335,389/91-04-02	Closed	NCV -	Failure to Follow Post Maintenance Test Control Procedures, paragraph 4.
335/91-04-03	Closed	NCV -	Failure to Restore 1B CCW Pump Missile Shield After Maintenance, paragraph 2a.
389/91-04-03	Closed	NCV -	Failure to Scope Change a NPWO-Controlled Test of 2B EDG Field Control Circuits, paragraph 3.
335,389/88-29-01	Closed	OPN -	In-plant Diesel Instrumentation Calibration, paragraph 7b.
335,389/88-30-02	Closed	URI -	Correlation Between Air and Steam on Safety Relief Valve Setpoints, paragraph 7a.
335/89-02-01	Closed	VIO -	Failure to Calibrate Six Regulatory Guide 1.97 Instruments, paragraph 8.

335/89-02-02	Closed	URI - Upgrade of EOP Training for Operators, paragraph 7a.

10. Abbreviations, Acronyms, and Initialisms

AC	Alternating Current
AFAS	Auxiliary Feedwater Actuation System
AFW	Auxiliary Feedwater (system)
AP	Administrative Procedure
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
avg	average
CCW	Component Cooling Water
CEA	Control Element Assembly
CFR	Code of Federal Regulations
CST	Condensate Storage Tank
DC	Direct Current
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EDSFI	Electrical Distribution System Functional Inspection
EOP	Emergency Operating Procedure
ESF	Engineered Safety Feature
F	Fahrenheit
FPL	The Florida Power & Light Company
FRG	Facility Review Group
FSAR	Final Safety Analysis Report
FT	Flow Transmitter
FYP	Five Year Plan
GE	General Electric Company
GMP	General Maintenance Procedure
HCV	Hydraulic Control Valve
HPSI	High Pressure Safety Injection (system)
I&C	Instrumentation and Control
ICW	Intake Cooling Water
IR	[NRC] Inspection Report
KV	KiloVolt(s)
KW	KiloWatt(s)
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LOI	Letter of Instruction
MCC	Motor Control Center (electrical distribution)
MFIV	Main Feed Isolation Valve
MOVATS	Motor Operated Valve Test System
MP	Maintenance Procedure
ms	millisecond
MSIV	Main Steam Isolation Valve
MTSI	Maintenance Tracking System
MV	Motorized Valve
NCV	NonCited Violation (of NRC requirements)

NPF	Nuclear Production Facility (a type of operating license)
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
ONOP	Off Normal Operating Procedure
OP	Operating Procedure
OPN	Open Item
PCM	Plant Change/Modification
PM	Preventive Maintenance
PWO	Plant Work Order
QI	Quality Instruction
RCS	Reactor Coolant System
Rev	Revision
rpm	Revolutions per Minute
RPS	Reactor Protection System
RWT	Refueling Water Tank
SFP	Spent Fuel Pool
SG	Steam Generator
St.	Saint
TCB	Trip Circuit Breaker
TS	Technical Specification(s)
URI	[NRC] Unresolved Item
V	Volt(s)
VIO	Violation (of NRC requirements)