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

Report Nos.: 50-335/91-21 and 50-389/91-21

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: October 15 - November 4, 1991

Inspectors: _____ 11/21/91
S. A. Elrod, Senior Resident Inspector Date Signed

_____ 11/21/91
M. A. Scott, Resident Inspector Date Signed

Approved by: _____ 11/22/91
K. D. Landis, 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, Unit 1 outage activities, fire protection review, and followup of headquarters and regional requests.

Results:

The Unit 1 refueling outage starting October 18, 1991, has had some minor setbacks but is essentially on schedule for completion on December 10, 1991. Several components did not operate properly or failed to start during safeguards testing (e.g., a main steam isolation valve, a containment spray pump, an injection valve, etc.). The 1B emergency diesel generator had a fan idler pulley shaft fail during a 24 hour test. Steam generator nozzle dam leakage delayed the outage for approximately three-fourths of a day. Many things during the initial part of the outage did go well (e.g., reduced reactor coolant system inventory operations and crane operations during the reactor head lift). Licensee management has been an active and a positive factor during this period.

Unit 2 continued to operate satisfactorily. A leaking hot leg injection check valve and a low pressure safety injection pump failure to start during safeguards actuation relay testing occurred during this inspection period.

In the areas inspected, violations or deviations were not identified.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

D. Sager, St. Lucie Site Vice President
* G. Boissy, Plant Manager
J. Barrow, Fire Prevention Coordinator
H. Buchanan, Health Physics Supervisor
* C. Burton, Operations Superintendent
R. Church, Independent Safety Engineering Group Chairman
* R. Dawson, Maintenance Superintendent
* R. Englmeier, Nuclear Assurance Manager
* R. Frechette, Chemistry Supervisor
* J. Holt, Plant Licensing Engineer
C. Leppla, I&C Supervisor
* L. McLaughlin, Plant Licensing Superintendent
* A. Menocal, Mechanical Maintenance Supervisor
T. Roberts, Site Engineering Manager
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
D. Wolf, Site Engineering 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

* 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 and then shut down on October 18, day 30 of power operation, for a refueling outage.

Unit 2 began and ended the inspection period at power - day 334 of power operation. A LPSI pump failure to start during testing and a leaking hot leg injection check valve were discussed in paragraph 2.

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 Intake Structure and ICW Platform;
- Unit 2 Steam Trestle Space;
- Unit 1 Containment Building; and
- Unit 2 CCW Platform.

Prior to the Unit 1 refueling outage on October 15, the inspectors accompanied an outage director, the electrical department technical assistant, who led the other outage directors on a tour of the Unit 1 electrical distribution system. The outage directors, who were company middle managers, were being familiarized with the distribution system specifics and the major system outage work items. The tour and discussion were considered beneficial by all parties.

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):

1-9-172 1B Battery Charger, and

1-10-357 V3247 1B2 Safety Injection Header Check Valve.

Early in the evening on October 18, 1991, Unit 1 started shutting down for its 11th refueling. The main turbine generator output breaker was opened at 12:05 a.m. on October 19. The TCBs for the CEAs were opened at 1:21 a.m. on October 19. The shutdown to Mode 3 was uneventful.

Immediately after the shutdown, portions of the safeguards testing commenced per OP 1-0400050, Rev 26, Periodic Testing of the Engineering Safety Features. Section 8.8 of the procedure tested the auxiliary feedwater automatic start using the AFAS system. This portion of the testing went satisfactorily with the RPS logic providing the reactor trip function and the AFAS providing its actuation function at the appropriate SG levels (20.5 and 19 percent levels, respectively). Section 8.5 of the procedure, Initiation of Main Steam Isolation, was partially performed before a control system failure halted the test. During the test, the control fuses for HCV-08-1A, the 1A MSIV, blew twice and the valve failed partially open under spring action alone instead of closed under combined spring action and air pressure. The 1B MSIV shut normally. The licensee plans to perform test section 8.5 at a later date.

The licensee took the necessary recovery steps when the 1A MSIV failed. The valve had been left partially off its seat such that one SJAE would not maintain condenser vacuum. This placed the plant in the TS 3.7.1.5 action statement that required the plant to be put into hot shutdown Mode 4 (less than 325 degrees F). The plant proceeded to this condition in a timely manner with sufficient regard for plant cooldown rate. The valve was later closed utilizing instrument air at a disassembled connection in the air control system.

The licensee found that a solenoid valve cap had leaked rain water and the solenoid shorted out. The vendor agreed to provide valve caps by the end of the outage that use O-rings vice flat gaskets and are both EQ qualified and submersible. The inspectors are continuing to follow this issue.

With decay heat steam still available in the early morning of October 19, mechanical maintenance tested the lift points on 8 of 16 main steam safety valves. The other 8 were being sent to a contractor for refurbishment and testing. NPWO 1114/61 was the work control

document. Procedure M-0705, Rev 16, Main Steam Safety Valve Maintenance, was the technical document that provided test instructions to check the lift points and adjustment instructions for the valves. Two valves required adjustment (discussed in paragraph 4) and all 8 valve tests were satisfactory, including the two tested following adjustment. Work was well coordinated between the operations, maintenance, and QC personnel who participated in the data collection and review.

On October 19, with Unit 1 in Mode 3, and the Unit 1 RCPs running, the technical staff performed portions of procedure 1-LOI-T-61, Rev 0, As Found Data Collection of RCP Seal Injection Flow Rate. This document mainly was used to gather existing condition data concerning the RCP seal injection feature. The seal injection scheme was per drawing 8770-G-078, sheet 111, Reactor Coolant Pump. The seal injection was implicated as part of a potential root cause scenario in the loss of the 1A1 RCP shaft in early summer of 1990. The collected data tended to not support the conclusion since the flow rates were less than those calculated to cause shaft damage. The technical staff plans to retest and adjust the flow rates at the end of the outage after the flow gages have been calibrated. The flow gages were not calibrated at the time of initial data collection for ALARA reasons and the desire to obtain true "as found" data.

In the evening of October 19, the inspector observed preparations for SDC subsystem warmup. This activity was per SOP 1-0410022, Rev 3, Shutdown Cooling - System Operating Procedure. Operators made the system lineups to go onto SDC and began to warm up the SDC heat exchangers and associated piping to reduce thermal shock when the warm (less than 325 degree F) RCS water would be valved in approximately 6 hours later. Warmup of the pipe outside of the containment was done in a recirculation mode using the LPSI pumps as a heat source.

In the early morning hours of October 21, the licensee performed portions of the Unit 1 safeguards test including a loss of offsite power test. This portion of the test is discussed in paragraph 3.c.

On October 21, as part of the Unit 1 safeguards test, a 24 hour load run was performed for both 1A and 1B EDGs. This 24 hour run was the result of recent change to the Unit 1 TS during its last refueling (spring of 1990). After approximately 6 hours, the 1B EDG suffered a failure of the 12-cylinder engine fan idler pulley shaft. This is discussed in paragraph 4.c. The 1B EDG was repaired, completed its load run, and was returned to service on October 28, prior to entering reduced RCS inventory conditions.

Prior to the 1B EDG being returned to service on October 23, there was a short period of approximately 5 hours in which the 1A EDG was also technically out of service. Since a fuel load received on site must remain in the receiving tank until its chemistry is established

- approximately 24 hours - the licensee shuffles fuel between tanks prior to receiving fuel to fill all but the one designated to receive that fuel load. Once the 1B EDG was thought repaired and test run for an hour, it was declared operable. Fuel was then shuffled from the 1A EDG fuel storage tank to support the 1B EDG second 24 hour load run and to prepare for fuel receipt to the 1A storage tank. The 1A EDG fuel storage tank was left about 1,000 gallons (6.5 hours run time) below the TS limit and 1B EDG was the one required operable EDG. Subsequently, the 1B EDG was again declared inoperable after nearly 12 hours of the second load run. Fuel logistics caught the licensee with not enough fuel in the 1A EDG fuel storage tank to call the 1A EDG operable.

This condition (both EDGs inoperable at one time) placed Unit 1 in a Mode 5 TS action statement. The LCO required that one EDG be returned to operability as soon as possible. All other required TS actions were reviewed for compliance. The licensee was timely in exiting the action statement by transferring fuel back to the 1A fuel storage tank and in pursuing 1B EDG repairs.

On October 29, Unit 1 entered a reduced RCS inventory condition to support SG nozzle dam installation. The following preparations occurred during this evolution (some were observed):

- Containment Closure Capability - Procedure GMP 1-M-0060, Rev 0, Closing of Containment Penetrations, Personnel Hatch, and Equipment Hatch, was issued to accomplish this; men and tools were on station (observed, see followup paragraph below).

- RCS Temperature Indication - Two independent CETs were available for indication. They were installed per I&C 1400087, Rev 1, Core Exit Temperature Monitoring During Reduced RCS Inventory, and verified by the licensee per OP 1-0410022, Rev 3, Appendix A, Instructions for Operation at Reduced Inventory or Mid-Loop Conditions, item 1.A.

- RCS Level Indication - Independent RCS wide and narrow range level instruments which indicate in the control room were operable per OP 1-0410022, Rev 3, Appendix A, page 1, item 1.E (observed). These were logged every 15 minutes and continuously monitored when RCS level was less than 31 feet, 3 inches, per OP 1-1600023, Appendix B, items 1.K and 1.M. An additional Tygon tube loop level indicator in the containment (observed) was manned during level changes per OP 1-0410022, Appendix A, page 2, item 5, and checked every shift during static conditions per OP 1-1600023, Appendix B, page 2, item 1.L.

- RCS Level Perturbations - When in a reduced RCS inventory condition, additional operational controls were invoked per OP 1-0410022, Appendix A, items 10 and 12. At plant daily meetings, operations took action to ensure that maintenance did

not consider performing work that might effect RCS level or shutdown cooling.

- RCS Inventory Volume Addition Capability - Nominally, one (of three) charging pumps and a HPSI pump (breaker racked in and control switch in STOP per OP 1-1600023, Appendix B, item 1.D) were available [observed].

- RCS Nozzle Dams - Satisfactorily installed per procedures OP 1-0410022, Appendix A, page 4; M-0029A, Steam Generator Primary Side Maintenance; and OP 1-1600023, paragraph 8.10 to 8.13. No initial leakage out of the dams was identified. Leakage was observed after the head lift; see the leakage discussion below in this paragraph.

- Vital Electrical Bus Availability - Operations would not release the switchyard, safety busses, or alternate power sources (EDGs) for work during this evolution per OP 1-0410022, Appendix A, item 2.B and OP 1-1600023, Appendix B, item 1.B. Both A & B safety-related 4160 and 480 Volt power trains were available.

The inspectors observed test (practice dry run) closure of the Unit 1 containment equipment hatch utilizing procedure GMP 1-M-0060, Rev 0, Closing of Containment Penetrations, Personnel Hatch and Equipment Hatch. Temporary change 1-91-236, based on NRC comments regarding work sequencing, was in effect. The hatch entry was cleared and the hatch was lowered into place in about eight and one half minutes. The hatch was secured in approximately 11 and one half minutes. Actual calculated maximum allowable hatch closure time would be generated based on RCS heatup rate (greater than one half hour nominal based on ONOP 1-0410022, Rev 3, Shutdown Cooling). The licensee performed the test with the normally available crew. As stated by the licensee, available throughout the outage was a portable crane at the entry to the hatch; this crane could facilitate the rapid removal of postulated large objects in the hatchway.

On October 31, Unit 2 developed a problem with check valve V3527 in the 2B hot leg injection path. Referring to drawing 2998-G-078, sheet 131, this TS-identified check valve is the first of two check valves off the RCS. Two motor operated valves (MOVs) that are normally open lie between the the check valves and a third check valve in the HPSI header. At 12:20 pm, annunciator Q-17 lit and alarmed, indicating high pressure between the first two check valves. The associated pressure gage (PIA 3320) that drove the annunciator indicated that pressure between the two check valves was equal to RCS pressure. The licensee took the following actions:

- verified that the signal to the pressure gage was real;

- performed an RCS leak rate evaluation (that showed no increase);

- attempted to open AOV 3571 whose intended function was to relieve pressure between the check valves (the AOV failed to operate);

- when the AOV failed to operate, operations personnel entered containment to observe AOV operation;

- shut the two MOVs in the line; and,

- issued a NPWO (XA91031044) to install a gage between the check valves and the MOVs at vent valve V3891.

The above was done to comply with TS 3.4.6.2 and more importantly to insure integrity of the RCS pressure boundary. At 12:00 a.m. on November 1, the gage at vent valve V3891 read zero psig, indicating that the second check valve off of the RCS was holding. The licensee was logging this pressure every two hours at the end of the inspection period.

At the end of the inspection period, the licensee was planning for the eventual repair of AOV 3571. Parts were available for the work. The problem with working this valve was that there was only single isolation between the AOV and the space between the check valves, which was at 2250 psig. There would be no safety problem with operating with the AOV failed closed, in that the safety position of the valve is closed. At the next plant shutdown, the valve was scheduled to be repaired.

On October 31, Unit 1 was performing an ESF actuation relay test in accordance with OP 2-0400053, Engineering Safeguards Relay Test (TS Table 4.3-2). During the test, the 2A LPSI pump failed to start on an actuation signal. The pump did not start on a manual start signal either. Operations personnel observed the appropriate control power lights were lit, then pulled the control power fuses and reinstalled them. Electrical maintenance personnel could find no problems with the components related to the electrical start. During the next manual start attempt, it started on the first try. At the end of the inspection period, this condition was a licensee open item pending resolution of an in-house event report.

On November 1, at approximately 8:30 p.m., the licensee initiated the Unit 1 reactor vessel head lift. The crane worked quite well and the overall procedure went smoothly. The head was set down on a stand at approximately 10:00 p.m..

During the lift on November 1, the licensee halted head movement at approximately 2 to 3 feet above the vessel flange to visually inspect the reactor vessel flange surface. During an inspection performed several days earlier with the head installed, boric acid, thought to be possible leakage, had been noted on one quadrant of the flange in the vicinity of three studs. With the head lifted, no defects were

noted during the inspection of the vessel flange. The underside of the head where the two head "O" rings are located will be inspected at a later date. Approximately a year ago, CE had issued an information bulletin on CEDM housing leakage that had been deemed not applicable to this site. The licensee will reconsider it during the head inspection.

At approximately 1:00 a.m. on November 2 with the head removed, the licensee noted a 1.5 to 2.5 gallons per hour leakage out of the 1A SG hot leg nozzle dam leakoff hose. Further reactor vessel subcomponent removal was halted. Refueling canal water level was at approximately 40 feet above the bottom of the RCS hot leg. Later the same day (from 11:42 a.m. to 8:00 p.m.) nozzle dam leakage was systematically monitored to determine actual leakage rate. During this time, the canal water level was raised to approximately 60 feet. The leakage rate remained approximately the same (temporarily went to 6 gph then dropped) and it was determined that the downstream seal of the two-seal dam was not leaking. Management made the decision to live with the leakage and to continue with the refueling.

During this inspection period, the licensee changed the policy on routine valve position checks. This had been previously discussed as reported in IR 335,389/91-11, which addressed a mispositioned valve event and related escalated enforcement action. Plant manager memorandum # 832, dated October 3, stated that, based on QC/QA checks and observations, there was sufficient assurance that valve position checks could be reduced in frequency. Starting from the week of October 14, checks would go from weekly to monthly. Operations has completed the procedure changes to accomplish this.

Past IRs had discussed scaffolding issues (e.g., 50-335,388/91-11). The licensee has in the past taken equipment out of service when scaffolding was to be constructed over the equipment and placed the equipment back in service after the scaffolding was removed. To reduce equipment out of service time, the licensee is planning a policy change. With an engineering scaffold standard in hand and after a procedurally-described evaluation, equipment would be placed back in service with scaffolding built above it. During scaffold construction and removal, the equipment would be out of service. Policy implementation is awaiting an engineering standard that should be available after the Unit 1 outage.

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, complete, 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.

Operational occurrences on both units have kept the licensee's staff sensitive to safety.

3. 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:

- I&C 1-1400162A, Rev 7, Reactor Protection System - RTD Time Response Test Data Collection; and

- OP 1-0700050, Rev 37, Auxiliary Feedwater Periodic Test - Data Sheet "D".

a. Procedure I&C 1-1400162A was administratively controlled by NPWO 8013/63 and AP 0010142, Rev 7, Unit Reliability - Manipulation of Sensitive Systems. Drawing 8770-B-327, sheet 381, showed the test point hookup. The I&C personnel bypassed each RPS channel in turn to collect the necessary test data. No adverse events occurred during this condition of having 2 out of 3 channel trip logic in lieu of the normal 2 out of 4. Operations prevented work on other sensitive systems and maintained the plant in a stable condition during the testing period.

Data reduction indicated that the RTD time response was less than five seconds on all four RPS channels, which was much less than the maximum of 14 seconds allowed under TS 4.3.1.1.3. The test consisted of a current being injected into each RTD to heat it up and then allowing the RTD to return to normal RCS ambient temperature in which the RTD was submersed. The main purposes of the test was to determine if 1) the air gap between the RTD sensing element and its surrounding protective jacket had changed and 2) to determine if any

buildup had occurred on the outside of the RTD's protective jacket or the weld juncture between the RTD and the RCS piping.

b. OP 1-0700050, data sheet D, was the procedure for the 18 month full flow test of the 1C AFW pump. This test was satisfactorily performed in the early morning hours of October 19 with the pump flow directed to both SGs.

c. The Unit 1 safeguards test with loss of offsite power as described in OP 1-0400050, Rev 26, Periodic Integrated Test of the Engineering Safety Features, was performed on the morning of October 19. The following components did not function properly during the simulated LOOP with ESF actuation:

COMPONENT	AUTOMATIC START OR CHANGE OF STATE	SUBSEQUENT MANUAL START OR CHANGE OF STATE
1A Containment Spray Pump	did not start	did not start
MV 3646, HPSI Injection Valve	did not open	manually opened
2B Reactor Cavity Fan	did not start	manually started
1B Charging Pump	did not start	manually started
1C Charging Pump	did not start	manually started
6B Shield Building Fan	did not start	manually started
FCV 03-1E	lost indication then subsequently closed	N.A.

The 1A ICW pump operated properly during the above test, but failed to start during a subsequent test (LOOP without ESF actuation, performed per another section of OP 1-0400050) due to a failed relay.

The licensee had submitted NPWOs to troubleshoot or repair these components and planned to test them prior to returning to power operation.

The observed tests were well controlled. The safeguards components that failed to operate properly were more numerous and significant than usually encountered. The licensee was aware of this and was in the process of taking corrective actions. The inspectors are continuing to follow this issue.

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:

a. NPWO 4017/65 was the work control document for the repairs to the 1B safety-related battery charger. The work performed was mainly a parts change out in accordance with procedure MP 0960167, Rev 1, Periodic Battery Charger Component Replacement. Temporary change 1-91-209 was in effect.

Six new controller output boards would not perform as described in C&D Co. charger TM. Previously, the removed output boards would put out 1/6 of the 100 percent output as required by the TM. The charger-vendor-supplied new output boards would generate the cumulative 100 percent output, but would not meet the the 1/6 output-per-board criteria. When contacted, C&D provided documentation that the 100 percent test was the only test required with the new boards. The licensee was placing this new vendor-provided information into their document system for incorporation into the TM.

Post-maintenance testing for the refitted 1B charger was satisfactory. The charger was placed into service on the "B" bus in paralleled with the 1BB charger. The DC load was shared between the 1BB and the 1B chargers within the 15-amp-difference acceptance criteria (actual loads were 44 and 53 amps).

b. NPWO 1114/61, discussed in paragraph 2, dealt with the setpoint testing of the Unit 1 main steam safety relief valves. Valves 8212 and 8216 were found to be out of tolerance during their as-found tests. The valves were found to lift at 1049 and 1050 psig respectively while the acceptance criteria per the maintenance procedure was 1015 to 1035 psig (nominal 1025).

The maintenance valve engineer wrote NCR 1-628 the morning of the tests identifying the two valves with the out of tolerance condition. The NCR asked the engineering group to evaluate the "as found" condition and consider the possibility of changing the plus-or-minus one percent tolerance to one that was more realistic. Unit 1 TS Table 4.7-1 required that the subject valve lift setting be 1040 psia plus or minus one percent (1040 psia minus atmospheric pressure would

give 1025 psig). Other utilities have attempted to change this tight tolerance. At the end of the inspection period, the engineering group had yet to answer the NCR.

c. In paragraph 2 above, a 1B EDG failure was mentioned. While being load tested for 24 hours, the 12-cylinder engine cooling fan idler shaft failed due to cyclic fatigue. The failure occurred at a shaft step change where a keyway intersected an undercut (a groove at the step change resembling a snap ring groove). When the shaft failed, the idler pulley fell free from the drive shaft and belts. A diesel engine high temperature alarm occurred prior to the EDG being shut down. The licensee stated that no engine or generator damage had been sustained.

Each Unit 1 EDG consists of two diesel engines, a 12-cylinder one and a 16 cylinder one, with one common generator between the engines. Each engine has a shaft extension that drives a large radiator fan via belts. For both the 1A and 1B EDGs, the 12-cylinder engine end had a different fan belt idler pulley configuration than the 16 cylinder engine end. The Unit 2 EDGs are from a different vendor and have a different fan arrangement.

For followup actions, the licensee took the following steps:

- researched past diesel equipment history;
- performed laboratory analysis of the shaft break;
- made and installed a new shaft of different design and material; and,
- performed limited visual checks on the running operable 1A EDG.

The 1B EDG had lost the same 12-cylinder engine fan idler shaft in 1987 in the same failure mode. At that time, the 1A EDG 12-cylinder fan idler shaft, that had been in service for 11 years, was moved into the 1B fan idler shaft position. Redesigned shafts had been installed at all other fan idler shaft locations on both EDGs (3 spots). These new shafts had a slightly better design (less sharp edges for stress risers) and a similar strength but different material composition. The switch of the 1A fan idler shaft to the 1B idler was made for operational considerations. No explanation was available for the non-replacement (at a later time) of the 1B EDG 12-cylinder fan idler shaft after the 1987 occurrence.

The laboratory analysis found that cyclic fatigue was a root cause for the failure. This line of thought was supported by the less stiff original material and the stress risers at the machining points of interest. Stress risers in the shaft where the primary focus with the October 21 failure.

At this point in the EDG repair, the licensee manufactured a new fan idler shaft, installed it, and began a second 24 hour load run on October 22. The applicable NPWO was 61/2382.

On October 23, about 12 hours into the 24 hour load run, the inspector observed fan belt perpendicular oscillation of approximately 3 and one half inches on a 28 inch run between pulleys. Some limited unmeasured belt movement had been noted at the start of the load run but it was significantly less than this observation. The load run was stopped, the EDG was secured, and the fan end support was examined.

Four cracked areas were found in the 12-cylinder engine fan support and attached idler shaft support. Stress risers were removed in these areas and other NDE-identified defects were addressed in the interim response to NCR 1-633. PCM 441-191M was issued to repair and stiffen the fan structure.

On October 24, the repaired 1B EDG was restarted for a new 24 hour load run. During this run, excessive fan belt oscillation was again noted. Again, the machine was stopped. The belt tensioner was straightened, several additional support fasteners were loosened and retorqued, several welds were remade, thicker metal plates were added, and the fan belts were readjusted. During this period a vendor supported evaluation of the fan support problem. The vendor's evaluation provided insight regarding the 12-cylinder engine providing the driving harmonic force for the vibration.

On October 27, the 1B EDG was restarted and observed to have reduced vibration. The EDG completed a 24 hour load run without problem and was declared operable by the operations department with management concurrence.

At the end of the inspection period, the licensee had not completed their evaluation of the 1B EDG (or overall Unit 1 EDG situation). Several meetings were held to discuss the events and problems. The licensee has indicated that after November 4, when electrical train work had commenced, further evaluation and consideration would be given the Unit 1 EDG fan support problem.

5. Outage Activities (62703)

The inspector observed the following overhaul activity during the ongoing Unit 1 outage:

NPWO 3584/61 was the work control document for the overhaul of the 1A containment spray pump. During pump disassembly, two linear indications where found on the suction side of the impeller. During the last Unit 1 outage, NCR 1-484 was generated on the 1B spray pump impeller for linear indications on the discharge side. At the time, Engineering dispositioned the NCR indicating replacement of the impeller with a new one in lieu of repair. Plant QC, who had evaluated both impellers via liquid penetrant testing, wrote Quality Control [deficiency] Report M91-682 to mechanical maintenance for disposition of the 1A linears and for the possibility of a

generic issue (i.e., two similar problems on the same type of subcomponent).

The observed outage activity was satisfactory. The QC department was alert in identifying the spray pump impeller as a repetitive problem.

6. Fire Protection Review (64704)

During the course of their normal tours, the inspectors routinely examined facets of the Fire Protection Program. During specific activity such as large scale test of fire protection systems, exercises, extensive repair or drills, the inspectors would observe. Normally the inspectors would review 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.

The observed activity was acceptable.

7. Onsite Followup of Events (Units 1 and 2)(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.

Paragraph 2 of this report discusses several problems or events that required inspector followup:

- Unit 1 EDG fan idler pulley shaft failure;
- Unit 1 safeguards test problems;
- Unit 2 leaking hot leg injection valve problems; and
- Unit 2 LPSI pump failure-to-start problems.

In all instances the licensee was in the process of taking corrective actions on these items.

8. Followup of Headquarters and Regional Requests (Units 1 and 2) (92701)

The following surveys and requests for information were processed during this inspection period:

- Containment hatch details;
- Fuel pool content and content tracking program;
- Pressurizer and reactor vessel level indicators and piping; and
- Component and unit cyclic and transient information.

9. Exit Interview (30703)

The inspection scope and findings were summarized on November 4, 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.

10. Abbreviations, Acronyms, and Initialisms

AFAS	Auxiliary Feedwater Actuation System
AFW	Auxiliary Feedwater (system)
ALARA	As Low as Reasonably Achievable (radiation exposure)
AP	Administrative Procedure
ATTN	Attention
cc	Cubic Centimeter
CCW	Component Cooling Water
CE	Combustion Engineering (company)
CEA	Control Element Assembly
CEDM	Control Element Drive Mechanism
CET	Core Exit Thermocouple
CFR	Code of Federal Regulations
CWO	Construction Work Order
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
FCV	Flow Control Valve
FPL	The Florida Power & Light Company
GMP	General Maintenance Procedure
gph	Gallon(s) Per Hour (flow rate)
HCV	Hydraulic Control Valve
HPSI	High Pressure Safety Injection (system)
I&C	Instrumentation and Control
ICW	Intake Cooling Water
IR	[NRC] Inspection Report
LCO	TS Limiting Condition for Operation
LOI	Letter of Instruction
LOOP	Loss of Offsite Power
LPSI	Low Pressure Safety Injection (system)
MOV	Motor Operated Valve
MP	Maintenance Procedure
MSIV	Main Steam Isolation Valve
MV	Motorized Valve
NCR	Non Conformance Report
NDE	Non Destructive Examination
NPF	Nuclear Production Facility (a type of operating license)
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
ONOP	Off Normal Operating Procedure

OP	Operating Procedure
PCM	Plant Change/Modification
PCM	PerCent Milli (0.00001)
psia	Pounds per square atmospheric
psig	Pounds per square inch (gage)
PSL	Plant St. Lucie
QA	Quality Assurance
QC	Quality Control
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
Rev	Revision
RPS	Reactor Protection System
RTD	Resistive Temperature Detector
RWP	Radiation Work Permit
RWT	Refueling Water Tank
SDC	Shut Down Cooling
SG	Steam Generator
SJAE	Steam Jet Air Ejector
St.	Saint
TC	Temporary Change
TCB	Trip Circuit Breaker
T/M	Technical Manual
TM	Technical Manual
TS	Technical Specification(s)