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

Report Nos.: 50-335/93-24 and 50-389/93-24

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: November 28, 1993 - January 1, 1994

Inspectors: _____ 1/27/94
S. A. Elrod, Senior Resident Inspector Date Signed

_____ 1/27/94
M. S. Miller, Resident Inspector Date Signed

_____ 1/27/94
R. P. Schin, Project Engineer Date Signed

Approved by: _____ 1/28/94
K. D. Landis, Chief Date Signed
Reactor Projects Section 2B
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection was conducted onsite in the areas of plant operations review, surveillance observations, maintenance observations, fire protection review, safety system inspection, preparation for refueling, review of nonroutine events, and followup of unresolved items.

Backshift inspection was performed on November 29, December 1, 14, 15, 17, 27 and 29.

Results: Plant Operations area:

Operations personnel continued to show good performance in maneuvering the units and in responding to off-normal conditions. However, weaknesses were observed in a resin transfer evolution in the areas of procedure quality, procedural adherance, and human factors. The following violation was identified:

VIO 335/93-24-01, Failure to Follow and Maintain Resin Transfer Procedure (paragraph 3.b.2).

Maintenance (and Surveillance) area:

Intake cooling water pump performance baseline testing, which required keeping two test versions active at the same time, was well coordinated by the plant test and code group and well controlled by the operators (paragraph 4.c).

Plant Support area:

A fire drill included good onsite interface and communication among site security and health physics personnel, the site fire brigade, and the local fire company (paragraph 6).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

D. Sager, St. Lucie Plant Vice President
* C. Burton, St. Lucie Plant General Manager
K. Heffelfinger, Protection Services Supervisor
* H. Buchanan, Health Physics Supervisor
J. Scarola, Operations Manager
R. Church, Independent Safety Engineering Group Chairman
* R. Dawson, Maintenance Manager
* W. Dean, Electrical Maintenance Department Head
J. Dyer, Maintenance Quality Control Supervisor
W. Bladow, Site Quality Manager
H. Fagley, Construction Services Manager
P. Fincher, Training Manager
R. Frechette, Chemistry Supervisor
J. Holt, Plant Licensing Engineer
J. Hosmer, Site Engineering Manager
L. McLaughlin, Licensing Manager
* G. Madden, Plant Licensing Engineer
A. Menocal, Mechanical Maintenance Department Head
C. Pell, Site Services Manager
L. Rogers, Instrument and Control Maintenance Department Head
C. Scott, Outage Manager
J. Spodick, Operations Training Supervisor
D. West, Technical Manager
J. West, Operations Supervisor
* C. White, Plant Licensing Engineer
W. White, Security Supervisor
D. Wolf, Site Engineering Supervisor
E. Wunderlich, Reactor Engineering Supervisor

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

NRC Personnel

H. Berkow, Project Director, Project Directorate II-2, NRR
K. Landis, Chief, Reactor Projects Section 2B, Region II
* S. Elrod, Senior Resident Inspector
* M. Miller, Resident Inspector
J. Norris, Senior Project Manager, Project Directorate II-2, NRR
R. Schin, Project Engineer, Region II
N. Stinson, Intern

* Attended exit interview

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

2. Plant Status and Activities

a. Unit 1

Unit 1 began the inspection period at 100 percent power. The unit was downpowered several times; once for main circulating pump packing replacement, and twice for condenser waterbox cleaning. The unit ended the inspection period in day 95 of power operation since turbine startup on September 28.

b. Unit 2

Unit 2 began the inspection period at 45 percent power in a derated capacity premised upon extending core life until the February, 1994, outage. On December 13, the operators began to increase unit power and achieved full power on December 16. Power was reduced to 30 percent on December 25 following a condenser tube leak. Repairs were completed the same day, and the unit reached full power on December 28. The unit ended the inspection period in day 59 of power operation since startup on November 3.

c. NRC Activity

Herbert N. Berkow, an NRR Project Director whose responsibilities include the St. Lucie Plant, and Jan A. Norris, NRR St. Lucie Project Manager, visited the site on December 6 through December 8. Their activities included a site tour, discussions with licensee management, and discussions with resident inspectors in preparation for the upcoming St. Lucie SALP board.

Kerry D. Landis, the NRC Region II Section Chief with responsibility for the St. Lucie Plant, visited the site on December 13 and 14. His activities included discussions with licensee management on recent enforcement actions and NRC-identified trends and an overview of resident office activities.

3. Review of Plant Operations (71707)

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 as well as equipment conditions were randomly verified both locally and in the control room. The following accessible-area ESF system and area walkdowns were made to verify that system lineups were in accordance with licensee requirements for operability and equipment material conditions were satisfactory:

(1) Unit 2 Containment Spray Hydrazine Addition Trains A & B

(2) Unit 1 ICW trains A and B

(3) Unit 1 AFW and RAB areas

During tours of the Unit 1 AFW and RAB areas, the inspector noted generally very good housekeeping, cleanliness, and material condition. The inspector also noted some deficiencies, including:

- A compressed nitrogen gas bottle outside the Unit 1 RAB was not restrained from falling over. The inspector observed no safety-related equipment nearby that would be susceptible to a potential missile hazard, however, the bottle was located near a walkway. When informed, operators promptly restrained the bottle with a rope.

- A local valve position indicator was reading incorrectly. MOV V2504, VCT Bypass, located inside the 1C charging pump room, locally indicated 68% open when the valve was actually closed. When informed, operators promptly initiated MWR 93020590 to adjust the local valve position indicator.

- Lights were out and not working in the Unit 1 letdown valve room. The dark room would reduce an operator's ability to operate valves in the room if needed. When informed, operators promptly asked the responsible maintenance personnel to install new light bulbs.

- Safety-related manual valve V09127, upstream isolation valve for the 1B AFW pump flow instrument, was corroding badly under its painted surface. About one foot from this small carbon steel valve, the carbon steel piping transitioned to stainless steel tubing. When informed, operators promptly initiated MWR 93020662 for replacement of the valve.

- Lagging was missing from about one foot of both pipes to FT-09-2C, 1C AFW pump flow instrument. Maintenance work request 93016091 tag was attached, which stated "needs freeze protection." The inspector requested that the licensee review this condition. The licensee found that the MWR had been canceled with no reason given. Since, several years ago, the temperature got low enough to affect such outdoor instrument lines, operators promptly initiated MWR 93020663 to replace the lagging.

(4) Unit 1 Charging Pumps and associated instrumentation

Recent decontamination efforts by the licensee's health physics organization resulted in increased accessibility to both units' charging pumps. The inspectors conducted a thorough walkdown of the three Unit 1 charging pump cubicles and noted the following conditions:

- 1A Charging Pump - Two closure bolts were missing on the stuffing box seal water tank, the valve position indicator on isolation valve V-2332 was loose, and a yellow polyethylene bag secured about the stuffing box drain valve was without identification as potentially contaminated. When informed, the licensee promptly initiated corrective actions.

- 1B Charging Pump - The stuffing box seal water tank level indicating switch was missing a plug on the low pressure vent port, and a tubing support for the charging pump discharge valve (V-2319) packing leakoff line was parted from the pump pedestal anchor point. When informed, the licensee promptly initiated corrective actions.

- Common to all pumps - The inspectors found that the low pressure sensing lines to the stuffing box seal/cooling water tanks' level indicating switches were disconnected, with the tubing leading to the tanks capped and the tubing leading to the switches open to atmosphere. The level indicating switches were differential pressure gages, originally designed with the low pressure ports sensing dry reference legs (air pressure above the tank water level) and the high pressure ports sensing the tank water column and air pressure. The tank water levels were indicated locally by sight glasses and low level conditions were alarmed remotely by the level indicating switches.

  Licensee technical staff engineers, in explanation, stated that the low pressure lines were disconnected early in plant life in response to instances where overfilling the tanks introduced water into the dry reference legs. While members of the licensee's Technical Staff could recall

generating a REA a long time ago to allow the disconnection of the low pressure lines, they could not produce documentation to support the decision, so they promptly generated NPWOs to reconnect the lines. Additionally, the licensee generated valve tags for the low pressure line blowdown valves (not normally identified by valve tags) so that procedural direction could be issued to operators for draining the lines should an overfill occur.

The inspector judged the licensee's corrective actions for plant tour items to be satisfactory.

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 ensure that operations and security performance remained at acceptable levels. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures. Control room annunciator status was verified. Except as noted below, no deficiencies were observed.

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

- 1-93-11-061 PM on CCW Pump 1C.
- 1-93-11-073 Isolate 1A ICW system to replace the flow transmitter instrument tap. This clearance was expanded because strainer drain valve SB-21334 leaked through and kept the weld area wet. The expanded clearance was satisfactory.
- 1-93-12-036 1B Emergency Diesel Generator.
- 1-93-12-002 PM on 1A Charging Pump.

The clearances were properly executed.

(2) The inspector witnessed operators and health physics personnel transferring radioactive spent resin from the spent resin tank to an outside shipping container. The governing documents were:

- OP 1-0520020, Rev 30, Radioactive Resin Replacement,

- HP-49, Rev 4, Dewatering Radioactive Bead Resins, and

- OM-048-NS, Rev 0, [Pacific Nuclear] Operating Procedure for Pacific Nuclear/Waste Services Group Resin Drying (Dewatering) System at Florida Power & Light - St. Lucie Plant.

At the beginning of the observation, SNPO qualified nonlicensed operators stationed in the Unit 1 auxiliary building basement were preparing to manipulate valves to transfer spent resin from the spent resin tank to a polyethylene high-integrity shipping container located in a ground shield outdoors in the alleyway behind the auxiliary building. The shipping container looked like a 6-ft-tall cylindrical jar and would hold about 175 cu ft of resin beads. The transfer path for the resin/water slurry was from the spent resin tank, through pipes and hoses, to a fill head mounted on top of the shipping container. The fill head contained a TV camera, shipping container level indicators, and shipping container level alarm sensors. The transfer was successfully completed without spillage but not entirely per the procedure. The inspector identified several procedure-related weaknesses or performance lapses during the evolution. Pertinent elements from the procedure follow:

- OP 1-0520020, Section 4.0, Limits and Precautions, stated that a Nuclear Watch Engineer [a licensed SRO] should coordinate and supervise each resin discharge operation.

- OP 1-0520020, Appendix L, Resin Transfer For Spent Resin Tank, specified some initial valve alignments then had a note to "ensure positive communication exists between the operator at the outside shipping container, RMW [reactor makeup water] valve, and the resin discharge valve before continuing with the procedure." A flow check followed.

- OP 1-0520020, Section 4.0, Limits and Precautions, required "Do not exceed system design pressure of 150 psig and SRT [spent resin tank] pressure of 25 psig or shipping container pressure of 10 psig during sluicing operations." Appendix L then had a caution that the hose and container could become plugged if enough water were not furnished. Avoid exceeding the cask inlet pressure of 10 psig and SRT pressure of 25 PSIG.

- OP 1-0520020 <u>did not</u> discuss valve manipulations to add water to the resin discharge pipe via a bypass line if the resin entering the shipping cask were judged to be too dry from its appearance on a television monitor at the tank.

This was stated to be a frequent problem but was not addressed in the procedure.

Conditions observed by the inspector included:

- The Nuclear Watch Engineer was not present at the scene during the transfer, nor was another person at the scene designated to be "in charge".

- The communications arrangement was not "positive" and deterred operators from adequate performance of their duties. The communications arrangement consisted of the Health Physics operator for the cask outside using a hand-held radio to call the telephone number for a wall phone around a corner and 45 feet down the hall from gage PI 6644 that displayed spent resin tank pressure. The radio was stated to quit frequently. When at the telephone, the operator could not see the gage to monitor spent resin tank pressure. Another operator that would manipulate the valves directly affecting spent resin tank pressure was located around a corner from this gage and about 15 feet away. The gage was not visible from this position.

- Operators did not monitor Gage PI 06-44, which displayed the "[10 psig limit] shipping container or cask inlet pressure." This gage, remotely located in the drumming room, was not manned nor was communication established. Also, it was a small size gage with a 160 psig full scale - not suitable for monitoring a 10 psig parameter.

  As a result of the communications and coordination failures above, when the transfer started, spent resin tank pressure rose to 37 psig, exceeding the 25 psig limit stated in the procedure. Later, the inlet valve was throttled to reduce the spent resin tank pressure to within its limit. Gage PI 06-44, located in the drumming room, exceeded the 10 psig procedural limit throughout the transfer, reading in the 17-20 psig range.

  Subsequent review by the licensee found that the "10 psig" requirement was no longer valid since the shipping cask had been changed from closed 55-gallon drums to open-top polyethylene "jars" years ago.

- Procedure OP 1-0520020 had not been updated to correct previously-identified inadequacies regarding adding bypass water to control the dryness of the resin bead slurry.

  As a result of failing to update the procedure, successful completion of the evolution required operations be performed outside of the procedure. The health physics person operating the cask dewatering controls arranged for

the operators to add water to the resin discharge pipe via a bypass line if he should judge the resin entering the shipping cask to be too dry from its appearance on the television. It was left to the operators to discover which flowpath and valve would accomplish this. During the transfer, the health physics person did determine that additional water was needed. The operators involved manipulated valves outside of the procedure to provide a bypass flow path and did provide the additional water desired.

When the transfer started, SRT pressure rose to 37 psig, exceeding the 25 psig limit stated in the procedure. Later, the inlet valve was throttled to reduce the SRT pressure to within its limit. The operator subsequently remembered that a radio repeater had been installed in the area. He borrowed a radio, which worked well and provided direct radio communications from the gage PI 6644 area to the health physics person outside. Gage PI 06-44, located in the drumming room, exceeded the 10 psig allowed by the procedure throughout the transfer, reading in the 17-20 psig range. During the transfer, the health physics person did determine that additional water was needed. The operators involved manipulated valves outside of the procedure to provide a bypass flow path and did provide the additional water desired.

The inspector judged that the equipment layout, coupled with procedural inadequacies and primarily the lack of supervision and coordination, contributed to the conditions observed.

Unit 1 TS 6.8.1.a requires that written procedures shall be established, implemented and maintained covering the activities recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Appendix A, paragraph 7.b, Solid Waste System, includes "spent resins and filter sludge handling." The licensee failed to adequately implement (follow) and maintain (update) OP 1-0520020, Rev 30, Radioactive Resin Replacement. This failure is violation 335/93-24-01, Failure to Follow and Maintain Resin Transfer Procedure.

(2) Unit 2 Condenser Tube Failure

On December 25, Unit 2 experienced a condenser tube failure which resulted in a required power reduction. At 7:20 a.m., operators were informed by the shift chemistry technician that SG cation conductivity indicated that a tube failure had occurred. The technician had noticed a local alarm in the laboratory upon returning from field activities. Conductivity was reported to be greater than 2 micromhos per cm. Operators entered ONOP 2-0610030, Rev 12, "Secondary Chemistry - Off Normal," which required a power reduction to less than 30 percent power within 4 hours. At 7:40 a.m., operators entered Action Level 3 due to conductivity

increasing to greater than 7 micromhos per cm. Action Level 3 required shutdown to mode 2 within 4 hours. The 2A1 condenser tube section was the suspected source based on conductivity readings. The downpower started at 7:40 a.m. The operators stopped the 2A1 main circulating water pump at 7:50 and reached 30 percent power at 10:30 a.m. The conductivity had begun to return to normal. The licensee evaluated the conditions and decided not to continue the power reduction to mode 2 based on 15.7 micromhos per cm being the maximum concentration reached, the short time in the condition, and the expected prompt exiting of the condition. This evaluation included Chemistry Department input and was published in the Night Orders for December 25. At 11:15 a.m., 2A SG was returned to Action Level 2 and 2B SG was returned to Action Level 2 at 11:58 a.m. SG chemistry was corrected to Action Level 1 by 10:20 p.m. that day and normal parameters by 4:25 a.m. on December 26. Since the tube leak had been repaired, the licensee started increasing power at 4:30 a.m. December 26 and reached full power at 1:10 a.m. on December 28.

The licensee has evaluated this incident and is pursuing the extension of the chemistry laboratory local alarm to the control room. This would give more response time and not depend on the chemistry technician noticing the alarm light upon returning from a task in the field.

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.

On December 15, the licensee began the use of a Biometrics brand access system at protected area gates. The system involved the use of key cards and hand readers to identify personnel prior to granting access to the protected area. The installation of the system has reduced the number of security guards required at the plant's two gates by eliminating the need for guards to issue badges. As a result of this action, personnel were required to

retain their badges upon exiting the protected area and to arrive at the plant with their badges in order to gain admittance. Prior to instituting the new process, the licensee promulgated information to plant personnel covering the new system's operation and informing personnel of their responsibilities with respect to carrying badges home (e.g., immediately reporting the loss of a badge).

The inspector found no major difficulties during observations of gate operations following the switch to the new system. The licensee's conversion to the Biometrics system has been generally trouble-free and indicates appropriate prior planning.

In conclusion, the licensee's operations personnel continued to show good performance in maneuvering the units and in responding to off-normal conditions. However, weaknesses were observed in a resin transfer evolution in the areas of procedure quality, procedural adherance, and human factors. These conditions resulted in violation 335/93-24-01.

4. 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:

a. OP 1-1400198, Revision 2, RPS Channel Calibration - Variable High Power Quarterly

b. OP 1-1400160, Revision 15, Channel Calibration - Delta T Power - Quarterly

c. AP 1-0010125A, Rev 32, Surveillance Data Sheets, Data Sheet 19 (Quarterly Pump Code Run of 1A ICW Pump)

The inspector witnessed several ICW pump tests over the report period when the licensee was changing the baseline flow configuration from 14,000 gpm split between the turbine cooling system and the CCWHX to 14,000 gpm all through the CCWHX. The single path gave a significantly smoother flowmeter reading and data consistency not obtainable using two gages to read data from two flow paths. These particular tests also verified that the A train - B train cross connect valves were not leaking.

In particular, several 1A ICW pump tests, witnessed on December 14 and 15, were performed per AP 1-0010125A, Rev 32, Data Sheet 19, TC 352. The TC reinstated the old, two path, procedure because the procedure had already been changed but changing baseline techniques required a successful test under the old rules, then a test under the new rules to get a comparison. The 1A pump had been in Alert status per the ASME Code since November 8. Alert status for pump pressure testing was defined in ASME Code table IWP 3100-2 as the test discharge pressure being in the range of either 90-93 percent or 102-103 percent of baseline pressure. The ASME Code required that the test frequency be doubled for pumps in Alert. Action is required when pump pressure tests outside the alert range, either high or low, as defined in ASME Code section 3230, Corrective Action. This required that a pump in that status be declared inoperative and not returned to service until repaired or determined to meet safety requirements. A new baseline is needed for pumps in the required action range.

- The first dual flow path test at 5:45 p.m., on December 14 resulted in 122.45 ft pump head. Being less than 125.3 ft, this left the pump in an Alert status.

- A second dual flow path test at 8:30 p.m., on December 14 was intended to equalize A and B header pressures to prevent leakage affecting pump head. This test resulted in 120.9 ft pump head, placing the pump in the Required Action Range.

- 1A ICW pump was placed out of service and the impeller lift clearance was adjusted that night. The 1C ICW pump was used for service while the 1A pump was being repaired.

- The post-maintenance dual flow path test at 8:45 a.m., on December 15 resulted in 130.5 ft pump head - a satisfactory result.

- The single flow path test at 10:45 a.m. on December 15 resulted in 130.2 ft pump head, which agreed well with the 8:45 a.m. dual flow path test. The new baseline document was issued that day. The change in pump head was evaluated as normal wear over the last year.

The inspector judged that ASME pump testing, which required keeping two test versions active at the same time, was well coordinated by the plant test and code group and well controlled by the operators.

5. 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 ensure that priority was assigned to safety-related equipment. Portions of the following maintenance activities were observed:

a. NPWO 8673/61, Replace ICW Half Coupling

b. NPWO 7151/65, Troubleshoot 1A EDG Immersion Heaters

The inspector observed troubleshooting activities associated with the 1A 16-cylinder EDG LO immersion heaters. Cooler weather experienced recently has resulted in the need to run the 1A EDG to maintain temperatures within specifications, indicating a potential problem with the EDG's immersion heaters. The inspector was present as electricians checked heater currents and phase-to-phase voltages. Results compared well to the 1A 12-cylinder EDG values, indicating that the heaters were performing satisfactorily.

Electricians questioned the accuracy of the thermometer which indicated LO temperature for the 16-cylinder engine. Accordingly, they obtained a surface pyrometer to measure LO pipe surface temperatures in the vicinity of the thermometer used to measure LO temperature on each engine. Pyrometer readings correlated well to indicated temperatures and the electricians concluded that the heater problem was, most likely, associated with the temperature switch which activated the heaters. A MWR was initiated for I&C to verify temperature switch calibration. At the end of the inspection period, this portion of the work had not been completed.

The inspector concluded that the troubleshooting activity was performed well, and that the electricians involved demonstrated a sound systematic approach in reaching their conclusions.

c. NPWO 8584/61, 1A2 CW Pump Repack

On December 6, Unit 1 operators reduced reactor power and stopped the 1A2 CW pump after an auxiliary operator reported that the pump upper bearing/packing housing had heated up to about 145 degrees F from a normal temperature of about 100 degrees F. This pump was being monitored closely because the lubrication water flow to it had previously decreased to about 5 gpm from a normal flow of 8 to 10 gpm. When this reduced flow had been observed, mechanical maintenance personnel had performed troubleshooting, determined that there were no obstructions in the lubrication water piping to the pump, and concluded that the reduced flow was probably caused by new parts with smaller clearances around the lower pump shaft. Licensee engineers and the vendor had concluded that continued pump operation with the reduced lubrication water flow was acceptable.

Mechanical maintenance personnel removed the packing and found that it appeared worn and also sufficiently extruded to partially obstruct a lubrication water leakoff path. They installed new packing. Operators then ran the pump, found that the lubrication water flow increased to seven gpm and the upper bearing/packing housing remained cool, and returned the pump to service. The inspector observed the pump during and after this maintenance, observed the old and new packing, and discussed the event with operators, engineers, and maintenance personnel.

The inspector noted excellent coordination among operators, mechanical maintenance personnel, and engineers in tending to the 1A2 CW pump.

d. 10 CFR 50.59 Evaluation for LOI-T-78

The inspector reviewed the 10 CFR 50.59 safety evaluation for LOI-T-78, revision 0, "Ultimate Heat Sink Air Accumulator Tank Repairs." The LOI was discussed in IR 93-22. The inspector found that the SE was, in general, satisfactorily prepared and reviewed. However, the inspector noted that the SE included references to personnel actions which were not detailed in the procedure. Specifically, with regard to temporary sources of nitrogen employed to maintain the UHS valves in a closed position during maintenance, the SE stated that "personnel will be standing by locally to ensure that, if needed, the valves will bleed off the nitrogen that will be provided to keep the valves from opening." LOI-T-78 included no precaution or requirement to have personnel stationed to carry out this function, nor did it assign these responsibilities.

The inspector concluded that a safety evaluation including compensatory measures not required by procedure was a poor practice.

6. Fire Protection Review (64704)

During the course of their normal tours, the inspectors routinely examined facets of the Fire Protection Program. The inspectors reviewed transient fire loads, flammable materials storage, housekeeping, control of hazardous chemicals, ignition source/fire risk reduction efforts, and fire protection training.

On December 8, the inspector observed portions of a fire drill involving the local fire department. The drill simulated a fire in the dry storage building located inside the RCA and behind the EDG buildings. The local fire department responded with a fire engine pumper, an ambulance, and a crew of firefighters. The fire engine and crew were brought into the RCA through a nearby gate, with FPL security and HP personnel participation. The drill involved interface and teamwork between the site fire brigade and the local fire department and went relatively smoothly. Fire hoses were run from water sources to the fire area and anti-contamination booties were worn. After the drill, the fire department crew had some

good comments and questions, which were answered by the site personnel.

The inspector concluded that the fire safety activities were well managed.

7. Engineered Safety Feature System Walkdown (71710)

The inspector performed a walkdown inspection of the HPSI and LPSI systems for Unit 1. The inspector compared the licensee's system lineup procedures against the system P&IDs and found agreement. The inspectors then conducted a walkdown of the accessible system valves and found the systems to be aligned appropriately.

The inspectors performed a walkdown of the Unit 1 safeguards areas to assess overall system condition. The inspectors found that the areas exhibited generally good housekeeping, that equipment appeared to be well-maintained and properly installed, that pump lubricating oil levels were satisfactory and that cooling water, where required, was aligned properly. The inspectors examined selected hangers and pipe supports and found them to be properly installed with the exception of trapeze hanger SIH-122, which was not plumb. The hanger had been installed at pipe 4-51-415 on the wrong side of an adjacent whip restraint, creating an angle with the vertical. The inspectors informed the licensee of this condition, and PWO 66829 was prepared to correct the condition.

The inspectors identified several electrical boxes (B-1000, B-1048A, B-43) that were not fully latched closed. The licensee promptly corrected these conditions. The inspectors identified a cleanout plug for the VCT floor drain system, which was located in the overhead of the safeguards room, which exhibited boron buildup. The licensee subsequently verified that this did not represent a significant diversion path into the safeguards room and prepared a NPWO to clean and seal the plug.

The inspectors examined selected instrumentation calibration data and found no deficiencies. The inspectors also verified that selected instrumentation was properly installed, functioning, and that significant process parameter values were consistent with normal expected values.

The inspectors reviewed HPSI and LPSI pump surveillance test records and found that surveillances were performed with the required periodicity and that results were satisfactory.

The inspectors concluded that this system appeared to be operable and well maintained.

8. Preparation for Refueling (60705) Unit 2

The inspector witnessed the receipt of new fuel during several days.

The inspector witnessed the licensee moving new fuel in shipping container serial 5091 by forklift from Unit 1 to Unit 2 fuel buildings. Elements observed included Reactor Engineering presence, vendor [ABB/CE]

presence, security arrangements at the Unit 2 door, operation and supervision of the forklift, and placing of the container for opening. This fuel movement was performed satisfactorily.

The inspector witnessed the licensee unloading and storing new fuel per OP 1610020, Rev 13, Receipt and Handling of New Fuel and CEAs. Review of the data sheets showed that operations had recorded minor conditions for several shipping containers; e.g., container 4683 had corrosion showing on certain strongback bolts but it had not transferred to the plastic fuel cover; and container 4702 had a trunion pin hole drilled offset. The inspector concluded, based on this record review and personal observation as containers were unloaded, that the licensee was conducting a detailed inspection of the shipping containers.

On-station operations observed included the movement of fuel containers by forklift in the vicinity of the unloading bay and container unloading by the licensee. Elements observed included Reactor Engineering involvement, vendor [ABB/CE] involvement, security activities, operation and supervision of the forklift, placing of the container for opening, container condition, container opening and initial inspection activities, radiological controls, fuel removal and transfer to the dry storage area.

- Container 4703 - Bundles K54 and K46 unloaded,
- Container 4641 - Bundles K34 and K22 unloaded,
- Container 4673 - Forklift operations, and
- Container 5076 - Forklift operations.

The inspector found that the crews were experienced and methodical, exhibiting teamwork and care in their tasks.

9. Onsite Followup of Written Nonroutine Event Reports (Units 1 and 2) (92700)

LERs were reviewed for potential generic impact, to detect trends, and to determine whether corrective actions appeared appropriate. Events that the licensee reported immediately were reviewed as they occurred to determine if the TS were satisfied. LERs were reviewed in accordance with the current NRC Enforcement Policy.

(Closed - Unit 2) LER 389/93-06, Inadvertent Start of the 2B Emergency Diesel Generator

On May 13, 1993, with Unit 2 at 100% power, Instrumentation and Control (I&C) personnel were performing the "Engineering Safeguards Relay Test" in coordination with operators. Due to personnel error and miscommunication between I&C personnel and operators, operators restored the EDG normal/isolate switches back to the normal position while the I&C personnel still had a test meter connected across an ESFAS relay contact - which resulted in an inadvertent start of the 2B EDG. The licensee counseled personnel involved on communications and the necessity of ensuring that test equipment is not installed when securing from a test. The licensee also revised the "Safeguards Relay Test" procedure to ensure

that test equipment is removed prior to operations resetting any actuations or restoring any equipment to normal operting status. The inspector verified that an appropriate precaution was added to the procedure. This LER is closed.

10. Onsite Followup of Events (Units 1 and 2)(93702)

Nonroutine plant events (described in paragraph 3) 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.

11. Followup of Unresolved Items (Units 1 and 2) (92701)

(Closed - Unit 1) URI 335/91-22-04, Seismic Mounting Bracket Missing From Containment Isolation Valve.

This item was discussed in detail in paragraph 2.a of NRC IR 335,389/91-22. It involved the identification of a U-bolt mounting bracket missing from the operator of primary water containment isolation valve MV-15-1 at penetration P-7 on December 18, 1991. The U-bolt was found laying on the floor below the valve. This valve was listed in TS Table 3.6.2 as a containment isolation valve and was required to be operable when containment integrity was required. In addition, isometric drawing PMW-25, Rev 8, dated September 8, 1976, showed valve I-MV-15-1 as Seismic Class I with a seismic restraint at the valve operator. This failure to have a seismic restraint installed as designed resulted in the issuance of this URI on January 22, 1992.

In order to resolve this issue, the licensee performed the following corrective actions:

- Analyzed the as-found condition and determined that required integrity of the support, the valve, and the penetration were not compromised by the missing U-bolt.

- Corrected the installation.

- Initiated detailed post-outage management walkdowns in the mechanical penetration room similar to those in the containment.

The inspectors have found these actions to be effective following subsequent shutdowns. This item has been shown not to be directly safety significant and the causal factors have been addressed. Since it is not a current concern, the item is closed.

12. Exit Interview

The inspection scope and findings were summarized on December 30, 1993, with those persons indicated in paragraph 1 above. The inspector

described the areas inspected and discussed in detail the inspection results listed below. Proprietary material is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Status	Description and Reference
335/93-24-01	open	VIO - Failure to Follow and Maintain Resin Transfer Procedure, paragraph 3.b.2.
335/91-22-04	closed	URI - Seismic Mounting Bracket Missing From Containment Isolation Valve, paragraph 11.

13. Abbreviations, Acronyms, and Initialisms

ABB	ASEA Brown Boveri (company)
AC	Alternating Current
AFW	Auxiliary Feedwater (system)
ATTN	Attention
cc	Cubic Centimeter
CCW	Component Cooling Water
CCWHX	Component Cooling Water Heat Exchanger
CE	Combustion Engineering (company)
CEA	Control Element Assembly
CFR	Code of Federal Regulations
CW	Circulating Water
DC	Direct Current
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Feature Actuation System
FPL	The Florida Power & Light Company
gpm	Gallon(s) Per Minute (flow rate)
HP	Health Physics
HPSI	High Pressure Safety Injection (system)
I&C	Instrumentation and Control
ICW	Intake Cooling Water
i.e.	that is
IR	[NRC] Inspection Report
JPE	(Juno Beach) Power Plant Engineering
JPN	(Juno Beach) Nuclear Engineering
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LO	Lubricating Oil
LOI	Letter of Instruction
LPSI	Low Pressure Safety Injection (system)
MOV	Motor Operated Valve
MV	Motorized Valve
MWR	Maintenance Work Request
NCV	NonCited Violation (of NRC requirements)
No.	Number

NPF	Nuclear Production Facility (a type of operating license)
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NRR	NRC Office of Nuclear Reactor Regulation
NWE	Nuclear Watch Engineer
ONOP	Off Normal Operating Procedure
OP	Operating Procedure
P&ID	Piping & Instrumentation Diagram
PI	Pressure Indicator
psig	Pounds per square inch (gage)
PSL	Plant St. Lucie
Pub	Publication
PWO	Plant Work Order
RAB	Reactor Auxiliary Building
RCA	Radiation Control Area
REA	Request for Engineering Assistance
Rev	Revision
RII	Region II - Atlanta, Georgia (NRC)
RMW	Reactor Makeup Water
RPS	Reactor Protection System
RWT	Refueling Water Tank
SALP	Systematic Assessment of Licensee Performance
SB	Safety Train B
SE	Safety Evaluation
SG	Steam Generator
SNPO	Senior Nuclear Plant [unlicensed] Operator
SRO	Senior Reactor [licensed] Operator
St.	Saint
TS	Technical Specification(s)
UHS	Ultimate Heat Sink
URI	[NRC] Unresolved Item
VCT	Volume Control Tank
VIA	By Way Of
VIO	Violation (of NRC requirements)
WR	Work Request