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

Report Nos.: 50-250/92-34 and 50-251/92-34

Licensee: Florida Power and Light Company
9250 West Flagler Street
Miami, FL 33102

Docket Nos.: 50-250 and 50-251 License Nos.: DPR-31 and DPR-41

Facility Name: Turkey Point Units 3 and 4

Inspection Conducted: December 5-31, 1992

Inspectors: for R. C. Butcher, Senior Resident Inspector — 1/26/93 Date Signed

for G. A. Schnebli, Resident Inspector — 1/26/93 Date Signed

for L. Trocine, Resident Inspector — 1/26/93 Date Signed

Accompanying Personnel

M. T. Janus, Reactor Engineer

Approved by: K. D. Landis, Chief
Reactor Projects Section 2B
Division of Reactor Projects — 1/27/93 Date Signed

SUMMARY

Scope:

This routine resident inspector inspection involved direct inspection at the site in the areas of monthly surveillance observations, monthly maintenance observations, operational safety, and plant events.

Results:

Within the scope of this inspection, the inspectors determined that the licensee continued to demonstrate satisfactory performance to ensure safe plant operations. In addition, the licensee, through self assessment, took prompt action to correct the following non-cited violation:

50-250,251/92-34-01, Non-cited Violation - Failure to document a change to a clearance order resulting in the leakage of approximately 125 gallons of component cooling water onto the containment floor (paragraph 3).

Weakness - A megawatt recorder with an incorrect range card was ordered and installed (paragraph 7.a).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

T. V. Abbatiello, Site Quality Manager
R. J. Earl, Quality Assurance Supervisor
R. J. Gianfrencesco, Support Services Supervisor
E. F. Hayes, Instrumentation and Controls Maintenance Supervisor
R. G. Heisterman, Mechanical Maintenance Supervisor
P. C. Higgins, Outage Manager
D. E. Jernigan, Technical Manager
H. H. Johnson, Operations Supervisor
V. A. Kaminskas, Operations Manager
J. E. Knorr, Regulatory Compliance Analyst
R. S. Kundalkar, Engineering Manager
J. D. Lindsay, Health Physics Supervisor
G. L. Marsh, Reactor Engineering Supervisor
* L. W. Pearce, Plant General Manager
M. O. Pearce, Electrical Maintenance Supervisor
* T. F. Plunkett, Site Vice President
* D. R. Powell, Services Manager
R. E. Rose, Nuclear Materials Manager
R. N. Steinke, Chemistry Supervisor
F. R. Timmons, Security Supervisor
* M. B. Wayland, Maintenance Manager
E. J. Weinkam, Licensing Manager

Other licensee employees contacted included construction craftsman, engineers, technicians, operators, mechanics, and electricians.

NRC Resident Inspectors

R. C. Butcher, Senior Resident Inspector
* G. A. Schnebli, Resident Inspector
L. Trocine, Resident Inspector

Accompanying NRC Inspector

M. T. Janus, Reactor Engineer

NRC Management on Site

J. R. Johnson, Deputy Director, Division of Reactor Projects, Region II
K. D. Landis, Chief, Reactor Projects Section 2B, Division of Reactor Projects, Region II

* Attended exit interview on December 31, 1992

Note: An alphabetical tabulation of acronyms used in this report is listed in the last paragraph in this report.

2. Plant Status

Unit 3

On December 4, 1992, Unit 3 was in Mode 1 and reactor power was being held at less than 30% for a chemistry hold. The following evolutions occurred on this unit:

- On December 4, 1992, at 9:50 a.m., a power reduction from 27% was commenced in order to facilitate turbine overspeed testing. Unit 3 entered Mode 2 at 10:45 a.m. A turbine roll was commenced at 6:00 p.m., and the unit entered Mode 1 at 6:30 p.m. Due to an unsatisfactory balance shot on the turbine, a power reduction was re-commenced, Mode 2 was re-entered at 7:50 p.m., and the turbine was tripped at 7:56 p.m.

- On December 6, 1992, at 5:18 p.m., Unit 3 entered Mode 1, and the turbine was placed on line at 5:50 p.m. At 6:30 p.m., reactor power was stabilized at 28% for a steam generator chemistry hold.

- On December 7, 1992, at 6:15 a.m., power ascension was commenced; and at 1:15 p.m., reactor power was stabilized at 47% in order to facilitate flux mapping and installation of NIS detector currents.

- On December 9, 1992, at 10:00 p.m., power ascension at a rate of 3% per hour was commenced. On December 10, 1992, power ascension was stopped at 2:00 a.m. due to a condensate oxygen problem. Power ascension was re-commenced at 3:00 a.m. At approximately 6:55 a.m., reactor power was stabilized at approximately 70%.

- On December 10, 1992, at 11:00 p.m., a 10% load reduction to 60% power was commenced to reduce the amount of steam leaking from a crack on the 3B MSR drain line. Another 10% load reduction to 50% power was commenced at 11:40 p.m. At 8:20 p.m. on December 11, 1992, a load reduction to 20% power was commenced to permit a Furmanite repair of the 3B MSR drain line steam leak. (Refer to paragraph 8.a for additional information.) Power ascension was commenced at 11:30 p.m. on December 11, 1992; and at approximately 7:40 p.m. on December 12, 1992, reactor power was stabilized at 90% in order to facilitate flux mapping.

- On December 13, 1992, at 1:40 a.m., permission was granted to allow the increase of power to 100%. Unit 3 was stabilized at 100% reactor power at 6:25 a.m.

- On December 21, 1992, at 4:00 p.m., a load reduction to 85% was commenced in order to induce Xenon oscillations to produce various incore axial offsets. At 6:30 p.m., reactor power was stabilized at 85%, and the testing was terminated at 8:15 p.m. due to problems with the flux mapper thimbles. Power ascension was commenced at 9:20 p.m., and 100% reactor power was reached at 11:30 p.m.

Unit 4

At the beginning of this reporting period, Unit 4 was operating at 100% power and continued operation at this power level throughout the period. The unit had been on line since October 27, 1992.

3. Followup on Inspector Followup Items (92701)

Actions taken by the licensee on the items listed below were verified by the inspectors.

(Closed) URI 50-250,251/92-28-03 - Determine How Vent Valve 3-737J Was Uncapped and Opened.

At 5:55 p.m. on November 5, 1992, the Unit 3 RCO noted a rapid increase in containment sump level with no observed change in RCS level. At 5:57 p.m., the CCW surge tank level was observed to be decreasing, and the RCO closed MOV-3-730 and CV-3-739 to isolate the leak. CCW surge tank level stopped decreasing when CV-3-739 was closed. This valve had been opened in preparation for stroke time testing in accordance with step 7.11.8 of procedure 3-OSP-206.2, Quarterly Inservice Valve Testing. At 6:00 p.m., an NO inside containment reported water around the excess letdown heat exchanger. At 6:15 p.m., CV-3-739 was briefly opened and reclosed to identify the source of the leakage, and the NO reported that water sprayed from excess letdown heat exchanger vent valve 3-737J. Approximately 125 gallons of CCW water had leaked through this vent valve onto the containment floor. A walkdown of the excess letdown heat exchanger identified this vent valve as being open and uncapped. No other valves were out of position. An initial mechanical maintenance investigation showed that no work was being performed on the mispositioned valve, and a clearance computer check showed that there was no clearance on this valve. At the time of this event, Unit 3 was in Mode 6, and the excess letdown heat exchanger was not in service. Vent valve 3-737J was subsequently closed and capped.

Because the licensee's initial investigations did not determine how or why excess letdown heat exchanger vent valve 3-737J had been opened and uncapped, operations personnel were instructed via a night order to add all vents and drains within the boundaries of the clearance as releasing steps on the clearance for verification of correct position prior to flow being initiated to a radioactive or non-radioactive system. The licensee also revised procedure 0-ADM-212, In-Plant Equipment Clearance Orders, to include the verification that all vent and drain valves within the clearance boundary are closed or closed and capped prior to clearance release unless a system lineup is to be performed prior to the system being filled or pressurized.

A subsequent investigation revealed that vent valve 3-737J was opened and capped during the hanging of Clearance Order No. 3-92-08-172-R on October 11, 1992. The purpose of this clearance was to permit work on a CCW relief valve (RV-3-715) located on the outlet side of the excess letdown heat exchanger by performance of the following actions:

isolation of CCW to the excess letdown heat exchanger, installation of a drain rig at a CCW drain valve (3-626C) located on the inlet side of the heat exchanger, and depressurization of the equipment by creation of a vent path via the opening of a test connection valve (3-737H) for the CCW supply to the heat exchanger and CCW drain valve 3-626C. During the hanging of this clearance, a question was raised regarding the adequacy of the vent path because both the vent and drain valves being utilized were located on the CCW supply line to the heat exchanger, and the CCW relief valve to be worked was located on the CCW return line from the heat exchanger. The questionable vent path was discussed with the ANPS, and a verbal change was made to the clearance to permit the uncapping and opening of vent valve 3-737J, which was located on the CCW return line from the heat exchanger. Although vent valve 3-737J was subsequently uncapped and opened, the verbal change to the clearance order was not documented, and the re-aligned vent valve was not tagged. As a result, this valve was not closed and re-capped when the remaining re-aligned valves were restored to their original positions on November 2, 1992. At the time of the event, Clearance Order No. 3-92-08-172-R remained open pending the removal of the drain rig and the capping of drain valve 3-626C. Subsequent to this event, steps were added to the clearance order to facilitate the closing and capping of vent valve 3-737J. This clearance order was released at 8:25 p.m. on November 5, 1992.

TS 6.8.1.a requires that written procedures be established, implemented, and maintained covering the activities referenced in Appendix A of Regulatory Guide 1.33, Revision 2, February, 1978. Item 1.c of this Appendix recommends the use of written procedures for equipment control. Paragraphs 5.2.6 and 5.11.6 of procedure 0-ADM-212, In-Plant Equipment Clearance Orders, require that valves (including vent, drain, and equalizing valves) which are aligned during clearance order execution be tagged and that the ANPS indicate resolution of any discrepancy by initialing on the clearance order. However, on October 11, 1992, a verbal change was made to Clearance Order No. 3-92-08-172-R in order to resolve a discrepancy and permit the uncapping and opening of CCW vent valve 3-737J; but the verbal change was neither documented nor initialled by the ANPS to indicate resolution of a discrepancy, and the re-aligned vent valve (3-737J) was not tagged. As a result, this valve was not restored to its original position, and approximately 125 gallons of CCW leaked through the vent valve onto the containment floor on November 5, 1992, when another CCW valve (CV-3-739) was opened in preparation for stroke time testing. This failure to follow a procedure is a violation. However, this violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B of the NRC Enforcement Policy. This item will be tracked as NCV 50-250,251/92-34-01, failure to document a change to a clearance order resulting in the leakage of approximately 125 gallons of CCW onto the containment floor. This item is closed.

4. Onsite Followup and In-Office Review of Written Reports of Nonroutine Events and 10 CFR Part 21 Reviews (90712/90713/92700)

The Licensee Event Reports and/or 10 CFR Part 21 Reports discussed below were reviewed. The inspectors verified that reporting requirements had been met, root cause analysis was performed, corrective actions appeared appropriate, and generic applicability had been considered. Additionally, the inspectors verified the licensee had reviewed each event, corrective actions were implemented, responsibility for corrective actions not fully completed was clearly assigned, safety questions had been evaluated and resolved, and violations of regulations or TS conditions had been identified. When applicable, the criteria of 10 CFR Part 2, Appendix C, were applied.

(Closed) Review of Special Report - Overpressure Mitigating System dated December 18, 1992.

This event was documented in NRC IR No. 50-250,251/92-28. On November 27, 1992, at approximately 2:55 a.m., the 3C reactor coolant pump was started during the fill and vent process. Soon thereafter, the Unit 3 pressurizer power operated relief valve PCV-3-455B opened due to high pressure in the reactor coolant system. At the time of the event, the reactor coolant system was water solid with no bubble in the pressurizer. Reactor coolant system pressure was 375 psig prior to the pump start and the temperature of the reactor coolant system was 127°F. Operations Procedure 3-OP-41.1, Reactor Coolant Pump, limits a reactor coolant pump start to times when the temperature of the steam generator is no more than 10°F greater than that of the reactor coolant system. This temperature limitation is required to be maintained to minimize the potential for a temperature induced pressure increase during the start of a reactor coolant pump.

Temperature measurements of blowdown from the steam generator were monitored starting at 11:30 p.m. on November 26, 1992, in accordance with 3-OP-41.1. The initial temperatures of the shell side water in the steam generators were found to be approximately 145°F. Feed and bleed of the steam generator shell side volume was begun and monitored until the blowdown temperature reached 128°F. Soon after reaching this temperature the 3C reactor coolant pump was started. The control operator conducting the start of the reactor coolant pump also started opening pressure control valve PCV-145 to help control a possible pressure increase due to a temperature differential between the reactor coolant system and the steam generator. PCV-145 is the outlet valve from the reactor coolant system letdown orifices. None the less, after the start of the 3C reactor coolant pump, PCV-3-455B opened relieving pressure in the reactor coolant system.

During the last week of November 1992, Turkey Point Unit 3 was in the process of filling and venting the reactor coolant system. Plant procedures specify 375 psig for filling and venting to allow for operating margin, since the Westinghouse technical manual identifies a minimum loop pressure of 325 psig for filling and venting operations. This pressure is to be maintained so that the starting pressure of the coolant loop does not fall below the 200 psid required across the number one seal of the reactor coolant pump.

The setpoint for the overpressure mitigating system is 415 psig plus or minus 15 psig.

The following are considered to have contributed to the inadvertent lift of PCV-3-455B:

- starting a reactor coolant pump with a solid reactor coolant system contributed because no pressure absorbing bubble in the pressurizer was available to mitigate a pressure increase;

- a differential temperature between the reactor coolant system and the steam generator resulted in an increase in pressure as an increase in the temperature in the bulk reactor coolant system occurred;

- a slow acting (by design) letdown outlet pressure control valve reduced the ability to quickly control pressure by use of the letdown system; and

- based upon the mass of the reactor head and its location outside the bulk residual heat removal cooling flow path, a potential thermal gradient could have existed which contributed to the pressure rise in the reactor coolant system after starting the reactor coolant pump.

Reactor coolant system pressure indications observed in the control room during the event, according to pressure indicator PI-3-402, never exceeded 400 psig. Graphs of pressure versus time, generated from the plant computer system, substantiate this finding.

Corrective actions were as follows:

- In accordance with the recommendation contained in the Westinghouse technical manual designated minimum pressure for a reactor coolant pump start, operating procedure 3/4-OP-41.1 has been revised to include a pressure for fill and vent operations of greater than 325 psig.

- A caution will be included to maintain the reactor coolant system pressure between 325 and 330 psig to allow margin to the overpresssure mitigating system setpoint.

The inspectors consider the licensee's actions adequate and no further followup is necessary. This item is closed.

5. Monthly Surveillance Observations (61726)

The inspectors observed TS required surveillance testing and verified that the test procedures conformed to the requirements of the TSs; testing was performed in accordance with adequate procedures; test instrumentation was calibrated; limiting conditions for operation were met; test results met acceptance criteria requirements and were reviewed

by personnel other than the individual directing the test; deficiencies were identified, as appropriate, and were properly reviewed and resolved by management personnel; and system restoration was adequate. For completed tests, the inspectors verified testing frequencies were met and tests were performed by qualified individuals.

The inspectors witnessed/reviewed portions of the following test activities:

- OP 4002.2, Safeguard Relay Rack Train A, B, - Periodic Test, for train B on Unit 3;

- Section 7.2, Main Turbine Trips Test, of 3-OSP-200.3, Secondary Plant Periodic Test; and

- 3-OSP-204, Accident Monitoring Instrumentation Channel Checks.

The inspectors determined that the above testing activities were performed in a satisfactory manner and met the requirements of the TSs. Violations or deviations were not identified.

6. Monthly Maintenance Observations (62703)

Station maintenance activities of safety-related systems and components were observed and reviewed to ascertain they were conducted in accordance with approved procedures, regulatory guides, industry codes and standards, and in conformance with the TSs.

The following items were considered during this review, as appropriate: LCOs were met while components or systems were removed from service; approvals were obtained prior to initiating work; activities were accomplished using approved procedures and were inspected as applicable; procedures used were adequate to control the activity; troubleshooting activities were controlled and repair records accurately reflected the maintenance performed; functional testing and/or calibrations were performed prior to returning components or systems to service; QC records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were properly implemented; QC hold points were established and observed where required; fire prevention controls were implemented; outside contractor force activities were controlled in accordance with the approved QA program; and housekeeping was actively pursued.

The inspectors witnessed/reviewed portions of the following maintenance activities in progress:

- troubleshooting and repair of megawatt recorder R-3-348 (Refer to paragraph 7.a for additional information.),

- troubleshooting and Furmanite repair of steam leaking from a crack on a 3B MSR drain line (Refer to paragraph 8.a for additional information.),

- troubleshooting and repair of lead lag controller TM-408C in rod control circuitry,

- troubleshooting and repair of Unit 3 flux mapper, and

- repair of 3B CCW/ICW heat exchanger outlet piping leak.

During the troubleshooting and repair of lead lag controller TM-3-408C in the rod control circuitry, the inspectors noted several discrepancies between the associated Hagan drawings [5610-M-430-217, T(AVG) Control System T(AVG)-T(Ref) T(Deviation), and 5610-M-430-219, T(AVG) Control System - Rod Speed] and the associated PODs [5610-T-D-12A, Rod Control System, and 5610-T-D-12B, T(AVG) Control and Insertion Limit Alarms]. These discrepancies involved the following:

- the number and characterization of the lead lag controllers (lead lag controllers TM-3/4-408A, TM-3/4-408B, and TM 3/4-408C as shown on Hagan drawing 5610-M-430-217 versus lead function TM-408B and lag noise filter TM-408C as shown on POD 5610-T-D-12B);

- the existence of a differential controller (TM-408C), which generates an error signal that is inputed to signal summator TM-408H, on POD 5610-T-D-12A and not on Hagan drawings 5610-M-430-217 or 5610-M-430-219;

- the input signals to signal summator TM-408H [power mismatch, median T(AVG), and T(REF) as shown on Hagan drawing 5610-M-430-219 versus a rods in signal, rods out signal, and T(REF) median T(AVE) error signal from differential controller TM-408C as shown on POD 5610-T-D-12A];

- the output signals from signal summator TM-408H [one output signal as shown on Hagan drawing 5610-M-430-219 versus two output signals (rods in/out and rod speed) as shown on POD 5610-T-D-12A]; and

- the input signals to rod speed control module SC-408 [three input signals (rods in, rods out, and rod speed) as shown on Hagan drawing 5610-M-430-219 versus two input signals (rods in/out versus rod speed) as shown on POD 5610-T-D-12A].

The I&C specialists that were queried were aware of the discrepancies and stated that the Hagan drawings were representative of the actual plant configuration. Later investigations revealed that the drawing discrepancies had been previously identified by the licensee and that they were documented in REA No. 89-667, Power Mismatch Circuitry for Auto Rod Control. In order to expedite the drawing correction process and emphasize the importance of attention to detail, the licensee plans to issue an updated REA.

For those maintenance activities observed, the inspectors determined that the activities were conducted in a satisfactory manner and that the work was properly performed in accordance with approved maintenance work orders. Violations or deviations were not identified.

7. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs, conducted discussions with control room operators, observed shift turnovers, and monitored instrumentation. The inspectors verified proper valve/switch alignment of selected emergency systems, verified maintenance work orders had been submitted as required, and verified followup and prioritization of work was accomplished. The inspectors reviewed tagout records, verified compliance with TS LCOs, and verified the return to service of affected components.

By observation and direct interviews, verification was made that the physical security plan was being implemented. The implementation of radiological controls and plant housekeeping/cleanliness conditions were also observed.

Tours of the intake structure and diesel, auxiliary, control, and turbine buildings were conducted to observe plant equipment conditions including potential fire hazards, fluid leaks, and excessive vibrations.

The inspectors walked down accessible portions of the following safety-related systems/structures to verify proper valve/switch alignment:

- A and B emergency diesel generators,
- control room vertical panels and safeguards racks,
- intake cooling water structure,
- 4160-volt buses and 480-volt load and motor control centers,
- Unit 3 and 4 feedwater platforms,
- Unit 3 and 4 condensate storage tank area,
- auxiliary feedwater area,
- Unit 3 and 4 main steam platforms, and
- auxiliary building.

Other observations and/or inspections were as follows:

a. During the recent Unit 3 refueling outage, seven obsolete recorders associated with turbine temperatures and generator megawatt monitoring were replaced in accordance with PC/M No. 90-294, Replacement of Obsolete H & W Speedomax Recorders. The

replacement recorders (L&N, Speedomax, 165 and 250 series recorders) were selected based on their function and based on the available space on the main control room panel. They differed from the existing recorders (L&N, Speedomax, H and W model recorders) in the number of input points, dimensional size, alarm features, accuracy, and reliability.

During the Unit 3 startup, it was noted that one of the replacement recorders (R-3-348 for generator megawatt output) was recording values equivalent to approximately two-thirds of the field input values. Investigation revealed that the range card on the new recorder was not compatible with the field inputs. Attachment 6, Obsolete Recorders Specifications Survey, of PC/M No. 90-294 indicated that an input of 1 millivolt on the range card would correspond with a 20 megawatt change on the recorder and that the recorder range was 0-800 megawatts. Therefore, in order to correspond with the 0-800 megawatt recorder range, a measuring circuit ranging from 0-40 millivolts was used in the obsolete recorder. However, Attachment 7, Existing/New Recorders Comparison Chart, of PC/M No. 90-294 incorrectly specified the measuring circuit range as 0-60 millivolts for a 0-800 megawatt recorder range; and since a 1-millivolt input change corresponded to a 20-megawatt difference on the recorder, the new recorder output was indicating as though the recorder range was 0-1200 megawatts instead of 0-800 megawatts. Because the part number for the replacement recorder indicated that the circuit type was to be customer specified, the incorrect measuring circuit range (0-60 millivolts in lieu of 0-40 millivolts) from Attachment 7 of the PC/M was carried forward on to the purchase order (No. C91680 90287), and a recorder with an incorrect range card was ordered and installed. The licensee discovered and corrected this problem at the first opportunity, and operators had other indication of generator megawatts in the control room. Although this instrument was not safety-ralated, the engineering lack of attention to detail in ordering parts for a control room instrument is considered to be a weakness.

As a result, the licensee temporarily changed the scale on the new recorder, and the appropriate range card was ordered and installed. The TEDB was also revised to indicate the correct measuring circuit ranges.

b. The licensee routinely performs QA/QC audits/surveillances of activities required under its QA program and as requested by management. To assess the effectiveness of these licensee audits, the inspectors examined the status, scope, and findings of the following audit reports:

Audit Number	Number of Findings	Type of Audit
QAO-PTN-92-036	-	Radiation Protection and Industrial Radiation Protection Program
QAO-PTN-92-039	-	PNSC and Instrumentation
QAO-PTN-92-042	-	TS 3/4.7.7, Sealed Source Contamination
QAO-PTN-92-044	-	November Performance Monitoring Audit

No additional NRC followup actions will be taken on the findings referenced above because they were identified by the licensee's QA program audits and corrective actions have either been completed or are currently underway. Plant management has also been made aware of these issues.

As a result of routine plant tours and various operational observations, the inspectors determined that the general plant and system material conditions were satisfactorily maintained, the plant security program was effective, and the overall performance of plant operations was good. Violations or deviations were not identified.

8. Plant Events (93702)

The following plant events were reviewed to determine facility status and the need for further followup action. Plant parameters were evaluated during transient response. The significance of the event was evaluated along with the performance of the appropriate safety systems and the actions taken by the licensee. The inspectors verified that required notifications were made to the NRC. Evaluations were performed relative to the need for additional NRC response to the event. Additionally, the following issues were examined, as appropriate: details regarding the cause of the event; event chronology; safety system performance; licensee compliance with approved procedures; radiological consequences, if any; and proposed corrective actions.

a. At 11:00 p.m. on December 10, 1992, a 10% load reduction from approximately 70% reactor power was commenced on Unit 3 in order to reduce the amount of steam leaking from a crack on the 3B MSR drain line. A second 10% load reduction was commenced at 11:40 p.m. At 8:20 p.m. on the following day, a load reduction to 20% reactor power was commenced to permit a Furmanite repair of the 3B MSR drain line steam leak. The leak was repaired, and power ascension was commenced at 11:30 p.m. on December 11, 1992.

b. At 6:45 a.m. on December 12, 1992, a hard ground was received on 3D01-47, 3A EDG Field Flashing and Control Power, and an A1 priority PWO was submitted. Initial investigations revealed that

all EDG trouble targets were clear and that normal control power and ready to start indications were present. However, preliminary troubleshooting of the 3D01-47 ground did not positively identify the cause, location, or severity. As a result, the licensee declared the 3A EDG out of service at 9:25 a.m. in order to facilitate the isolation of the starting air to permit more extensive troubleshooting of the 3A EDG control circuit without risking an inadvertent start. Action statement b for TS 3.8.1.1.b was entered. This required the demonstration of the operability of the startup transformers and their associated circuits per TS 4.8.1.1.1.a within one hour, the demonstration of the operability of the remaining required EDGs per TS 4.8.1.1.2.a.4 within 24 hours, and the restoration of the inoperable EDG to operable status within 72 hours. The startup transformers and their associated circuits were verified to be operable at 10:10 a.m.. Operability testing of the 4A EDG was completed at 2:30 p.m., and operability testing of the 3B EDG was completed at 9:00 p.m. The ground was located and repaired, and the 3A EDG was tested and returned to service at 1:00 a.m. on December 13, 1992.

Violations or deviations were not identified.

9. Management Meeting (94702)

A meeting with the FPL engineering staff was held on December 11, 1992, at the FPL Juno Beach, FL office. The topics of discussion included efforts to lessen FPL dependence on AEs and strengthen the capabilities of the PEG groups, FSAR updating efforts, Technical Alerts (within FPL), maintenance support initiatives, and drawing consolidation/improvement status. A tour of engineering's new facilities and an open discussion period completed the meeting. This meeting was beneficial in keeping the NRC informed of licensee initiatives and aware of the status of ongoing enhancements.

10. Exit Interview (30703)

The inspection scope and findings were summarized during management interviews held throughout the reporting period with the Plant General Manager and selected members of his staff. An exit meeting was conducted on December 31, 1992. The areas requiring management attention were reviewed. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee. The inspectors had the following findings:

Item Number	Description and Reference
50-250,251/92-34-01	NCV - Failure to document a change to a clearance order resulting in the leakage of approximately 125 gallons of CCW onto the containment floor (paragraph 3).

Weakness	A megawatt recorder with an incorrect range card was ordered and installed (paragraph 7.a).

11. Acronyms and Abbreviations

ADM	Administrative
AE	Architect - Engineer
ANPS	Assistant Nuclear Plant Supervisor
AVG	Average
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CV	Control Valve
EDG	Emergency Diesel Generator
F	Fahrenheit
FPL	Florida Power & Light
FSAR	Final Safety Analysis Report
H&W	Hagan & Westinghouse
I&C	Instrumentation and Controls
ICW	Intake Cooling Water
IR	Inspection Report
L&N	Leeds & Northrup
LCO	Limiting Condition for Operation
MOV	Motor Operated Valve
MSR	Moisture Separator Reheater
NCV	Non-Cited Violation
NIS	Nuclear Instrumentation System
NO	Nuclear Operator
NRC	Nuclear Regulatory Commission
OP	Operating Procedure
OSP	Operations Surveillance Procedure
PC/M	Plant Change/Modification
PCV	Pressure Control Valve
PEG	Production Engineering Group
PI	Pressure Indicator
PNSC	Plant Nuclear Safety Committee
POD	Plant Operating Drawing
psid	pounds per square inch differential
psig	pounds per square inch gauge
PTN	Plant Turkey Nuclear
PWO	Plant Work Order
QA	Quality Assurance
QAO	Quality Assurance Organization
QC	Quality Control
R	Recorder
RCO	Reactor Control Operator
RCS	Reactor Coolant System
REA	Request for Engineering Assistance
REF	Reference
RV	Relief Valve
SC	Speed Controller
T	Temperature
TEDB	Total Equipment Data Base

TM	Temperature Module
TS	Technical Specification
URI	Unresolved Item