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

Report Nos.: 50-250/89-43 and 50-251/89-43

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 3 and 4

Inspection Conducted: August 26, 1989 through September 29, 1989

Inspectors: R. V. Crlenjak for — 10/27/89
R. C. Butcher, Senior Resident Inspector — Date Signed

R. V. Crlenjak for — 10/27/89
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R. V. Crlenjak for — 10/27/89
G. A. Schnebli, Resident Inspector — Date Signed

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R. V. Crlenjak, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope:

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

Results:

One Violation, one Non-Cited Violation and one Inspector Followup Item were identified as follows:

Violation for an inadequate clearance resulting in disassembly of a valve in a pressurized system.

Non-Cited Violation for adjustment of CCW flow control valves that reduced flow to one ECC below design requirements.

Inspector Followup Item for implementation of procedural changes to ensure only qualified operators assume shift duties.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

J. W. Anderson, Quality Assurance Supervisor
*J. Arias, Technical Assistant to Plant Manager
*L. W. Bladow, Quality Assurance Superintendent
*J. E. Cross, Plant Manager - Nuclear
R. J. Earl, Quality Control Supervisor
*T. A. Finn, Assistant Operations Superintendent
R. J. Gianfrencesco, Assistant Maintenance Superintendent
*S. T. Hale, Engineering Project Supervisor
K. N. Harris, Vice President
E. Hayes, Instrumentation and Control Supervisor
G. Heisterman, Electrical Assistant Superintendent
*V. A. Kaminskas, Technical Department Supervisor
J. A. Labarraque, Senior Technical Advisor
G. Marsh, Reactor Engineering Supervisor
*R. G. Mende, Operations Supervisor
L. W. Pearce, Operations Superintendent
*D. Powell, Regulatory and Compliance Supervisor
*G. M. Smith, Service Manager - Nuclear
J. C. Strong, Mechanical Department Supervisor
*G. A. Warriner, Supervisor Guality Control
M. B. Wayland, Maintenance Superintendent
J. D. Webb, Assistant Superintendent Planning and Scheduling

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

*Attended exit interview on September 29, 1989

Note: An Alphabetical Tabulation of acronyms used in this report is listed in paragraph 12.

2. Followup on Items of Noncompliance (92702)

A review was conducted of the following noncompliances to assure that corrective actions were adequately implemented and resulted in conformance with regulatory requirements. Verification of corrective action was achieved through record reviews, observation and discussions with licensee personnel. Licensee correspondence was evaluated to ensure that the responses were timely and that corrective actions were implemented within the time periods specified in the reply.

(Closed) Violation 50-250,251/88-25-01. Concerning inadequate Maintenance procedures for the spent fuel pool cooling pumps. The licensee responded

to this violation in letter L-88-466 dated October 26, 1988. The corrective actions taken by the licensee were found to be adequate and included the following; maintenance procedures were revised to incorporate specific instructions for oiler installation, maintenance department personnel were trained in proper installation and maintenance of oilers, inspection of oilers on all safety related pumps was conducted and deficiencies noted were corrected, and the addition of specific instructions to PM work instructions as to the proper maintenance for pumps with oilers. This item is closed.

3. Followup on Inspector Followup Items (IFIs), Inspection and Enforcement Information Notices (IENs), IE Bulletins (IEBs) (information only), IE Circulars (IECs), and NRC Requests (92701).

   (Closed) IFI 50-250,251/86-05-03, Licensee Modify IST Program to Delete the Exemption Request for Steam Generator Blowdown Valves. The licensee deleted the exemption request from their IST program. The inspector reviewed the exemption/relief requests in the Turkey Point Unit Nos. 3/4 Second Ten-Year Inservice Testing Program, Revision 0, dated December 12, 1988, and verified that the request had been deleted.

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

   The Licensee Event Reports (LERs) discussed below were reviewed and closed. 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 that 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 2, Appendix C, were applied.

   (Closed) LER 50-251/88-08, Inadvertent Relay Actuation Following Examination Causes Phase "A" Containment Isolation. On August 15, 1988, engineering personnel were performing an examination of the QR-44 safeguards relay rack and at the completion of their examination a wire bundle was moved to facilitate the closure of the panel door. The movement of the wire bundle resulted in a phase "A" containment isolation. The licensee determined that the event was caused by the wire bundle bouncing the contacts of relay 4-S1A2. The licensee issued PC/M 88-252 to install protective guards for the safeguards relays in relay racks 4QR42, 4QR43, 4QR44, and 4QR45. The inspector determined, through the review of the PC/M, that the work had been completed and the PC/M closed on March 16, 1989. The inspector found the licensee's corrective actions to be acceptable.

(Closed) LER 50-250/88-30, Instrument Loop Error and Installation Error Caused Accumulator Level Instrumentation Inability to Assure Technical Specification Limits Met. The licensee in response to this event performed an evaluation to determine if the identified level deviations in the accumulators had an affect on the Unit 3 accumulators to perform their intended safety functions. In addition, the licensee replaced the Unit 3 and 4 accumulator level transmitters with instruments which have a narrower setpoint span. The inspector reviewed the licensee's safety evaluation, JPN-SEIS-89-051, Safety Injection Accumulator Level Transmitter Nuclear Safety Issue, Revision 0, dated May 3, 1989. The licensee's evaluation identified that the worst case level error occurred on transmitter 3-LT-920, 3-LT-924 and 3-LT-926. Transmitters 3-LT-920 and 3-LT-924 deviated 13.5 gallons less than the required TS allowable minimum volume of 6544 gallons and transmitter 3-LT-926 deviated 18.5 gallons more than the required TS allowable maximum volume of 6664 gallons. The inspector's review of the evaluation concluded that the level deviation did not affect the ability of the accumulators to perform their function. In addition, the inspector reviewed the closeout of PC/M 88-536, Safety Injection Accumulator Level Transmitter Replacement, and the post maintenance testing associated with the Unit 4 accumulator channel "A", L-4-922 calibration. The inspector verified that the Unit 4 accumulator level transmitter replacement and system acceptance and turnover to plant operations was completed on April 1, 1989. The inspector also reviewed post maintenance instruction, 4-PMI-062.4, Accumulator "A" Level Channel L-4-922 Calibration, dated August 1, 1989, and the "A accumulator level channel calibration results and determined that the results met the acceptance criteria.

5. Monthly Surveillance Observations (61726)

The inspectors observed TS required surveillance testing and verified: That the test procedure conformed to the requirements of the TS, that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that limiting conditions for operation (LCO) were met, that test results met acceptance criteria requirements and were reviewed by personnel other than the individual directing the test, that deficiencies were identified, as appropriate, and were properly reviewed and resolved by management personnel and that system restoration was adequate. For completed tests, the inspectors verified that testing frequencies were met and tests were performed by qualified individuals.

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

0-OSP-023.1	Diesel Generator Operability Test
4-OSP-041.1	Reactor Coolant System Leak Rate Calculation
3-OSP-059.5	Power Range Nuclear Instrumentation Shift Checks and Daily Calibrations
4-OSP-050.4	Residual Heat Removal System Flowpath Verification While in Residual Heat Removal Cooldown Operation

No violations or deviations were identified in the areas inspected.

6. Engineered Safety Features Walkdown (71710)

The inspectors performed an inspection designed to verify the operability of the Unit 4 Main Steam Isolation Valve Air Accumulator backup system. This was accomplished by performing a complete walkdown of all accessible equipment. The following criteria were used, as appropriate, during this inspection:

a. Systems lineup procedures match plant drawings and as built configuration.

b. Housekeeping was adequate and appropriate levels of cleanliness are being maintained.

c. Valves in the system are correctly installed and do not exhibit signs of gross packing leakage, bent stems, missing handwheels or improper labeling.

d. Hangers and supports are made up properly and aligned correctly.

e. Valves in the flow paths are in correct position as required by the applicable procedures with power available and valves were locked/lock wired as required.

f. Local and remote position indication was compared and remote instrumentation was functional.

g. Major system components are properly labeled.

No violations or deviations were identified in the areas inspected.

7. Monthly Maintenance Observations (62703)

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

The following items were considered during this review, as appropriate: That LCOs were met while components or systems were removed from service; that approvals were obtained prior to initiating work; that activities were accomplished using approved procedures and were inspected as applicable; that procedures used were adequate to control the activity; that troubleshooting activities were controlled and repair records accurately reflected the maintenance performed; that functional testing

and/or calibrations were performed prior to returning components or systems to service; that QC records were maintained; that activities were accomplished by qualified personnel; that parts and materials used were properly certified; that radiological controls were properly implemented; that QC hold points were established and observed where required; that fire prevention controls were implemented; that outside contractor force activities were controlled in accordance with the approved QA program; and that housekeeping was actively pursued.

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

- Replacement of "B" Emergency Diesel Generator Temperature Switch.
- Repair of "A" Emergency Diesel Generator Air Compressor.
- Repair of Unit 4 Condenser Tube Leaks.
- Replacement of 3B Steam Generator Feed Pump Rotor.
- Corrective Actions for Components That Failed During the Unit 4 Trip (see paragraph 9).

No violations or deviations were identified in the areas inspected.

8. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs, conducted discussions with control room operators, observed shift turnovers and confirmed operability of instrumentation. The inspectors verified the operability of selected emergency systems, verified that maintenance work orders had been submitted as required and that 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.

Plant housekeeping/cleanliness conditions and implementation of radiological controls were 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 to verify operability and 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
Auxiliary Building

Regional Office Notice No. 2601 was issued to provide guidance for Regional verification of licensee methods for control of the license status of reactor operators on watch. This is resident action item 89-34. The licensee has established an administrative method for ensuring that a licensed operator that fails the requalification examination is removed from licensed duties and this was documented in Inspection Report 50-250,251/89-27. The licensee periodically issues a shift assignment duty roster. This document identifies the qualified licensed operator personnel and their shift assignments, non-licensed personnel, and personnel in the operator licensing training program. As the status of an individual changes, this list is revised appropriately. With respect to an operator's ability to perform licensed duties, Administrative Procedure, 0-ADM-200, Conduct of Operations, Revision 55, dated June 1, 1989, identifies that it is the responsibility of the PS-N to monitor the qualifications, physical condition and the mental capacity of the on-shift operations personnel. In addition, in order to assist the PS-N and the APS-N in the recognition of substance abuse the licensee fitness for duty program requires that all supervisory personnel be trained to identify the symptoms of behavioral unreliability and alcohol/drug abuse, techniques for discussing fitness for duty concerns with an employee, and actions required to remove the employee from duty. Requalification training in this area is required for all supervisors on an annual basis. In addition, Administrative Procedure, AP 103.48, dated May 3, 1989, established a method for tracking reassignments of licensed operators, termination of employment, and disability or illness as described in 10 CFR 55.25 and reporting these status changed to the NRC under the requirements of 10 CFR 50.74. The licensee has also outlined procedure revisions to ensure that only qualified individuals assume a shift. These revisions include a requirement for each oncoming licensed watchstander to review the list of individuals not qualified to stand watch. This list was recently placed in the control room and is kept current by the PS-N. The list outlines the reason(s) for disqualification such as failure of a requalification exam, NRC physical, simulator failure, license revoked, medical problem, etc. The procedure changes will require that the PS-N and Operations Supervisor be notified verbally when the status of any operator changes. The implementation of these changes should prevent non-qualified individuals from assuming licensed positions. The inspectors will review the completed procedure changes and this item will be tracked as IFI 50-250,251/89-43-02. In summary, the licensee's current program relies on the training department and the PS-N to assure that the operator on watch is qualified and is fit to perform the required licensed duties.

A. The inspectors performed a review of the following Operator Aids and Temporary Information tags to verify that they were being controlled in accordance with AP 0103.36, Control of Operator Aids and Temporary Information Tags, dated March 10, 1987.

Operator Aids

0-88-024	-	10 Meter Tower Recorder
0-89-011	-	Unit 3 Acoustic Valve Monitor
0-88-047	-	Unit 3 Radiation Monitor (R-18)

Temporary Information Tags

T-89-58	-	Unit 3 Process Radiation Monitors
T-87-86	-	B Emergency Diesel Generator
T-89-120	-	Unit 4 Boric Acid/Primary Water Totalizer
T-88-194	-	4A Intake Cooling Water Pump Ammeter
T-89-163	-	MOV-4-832 Component Cooling Water Surge Tank Fill Valve
T-87-272	-	Unit 4 Temperature Module (TM-409A) Position Switch
T-89-155	-	Unit 4 Alternate Shutdown Panel for LT-4-462
T-89-156	-	4B Normal Containment Cooler

The inspectors noted the following discrepancies:

(1) Temporary Information Tag T-87-86 was hung at the "B" EDG, however, this tag was not listed in the Temporary Information Tag index.

(2) Temporary Information tag T-89-155 was hung at the Unit 4 ASP instructing the RCO to read pressurizer level from a level instrument located in the AFW room due to LT-4-462 being isolated inside containment. However, LT-4-462 was returned to service on August 23, 1989, therefore, this tag was no longer required.

The licensee was made aware of these minor discrepancies and is taking corrective action.

B. The inspectors performed a review of the following Caution tags to verify that they were being controlled in accordance with AP 0103.41, Caution Tag Clearance Procedure, dated December 11, 1986:

9-24-88-1	"B" EDG local/normal transfer switch
4-13-89-1	POV-4-4882, To open turn clockwise
4-13-89-2	POV-4-4883, To open turn clockwise
4-17-89-1	POV-4-4882, Valve stem could eject when closing

4-17-89-2	POV-4-4883, Valve stem could eject when closing

The inspectors noted the following discrepancies:

(1) Tags 4-17-89-1 and 4-17-89-2 were hung on the valve handwheel and are listed in the index as being current. However, this condition was repaired prior to the valves being placed in service, therefore, these tags are no longer applicable.

The licensee was made aware of these minor discrepancies and is taking corrective action.

C. The inspectors reviewed the following equipment clearance orders to verify that they were being controlled in accordance with AP 0103.4, In-Plant Equipment Clearance Orders, dated July 27, 1989:

3-89-07-095	Steam Supply Valve to "A" Gas Stripper
3-89-07-092	CV-3-1003 B and CV-4-1003 B, Pressurizer Relief Tank (PRT) drain to containment sump.

The inspectors noted an event that was entered into the Unit 3 RCO logbook on August 27, 1989, that was not entered in the APSN logbook. A Safety Injection cold leg MOV 3-843A was found with the breaker open at 4:50 a.m., thus removing electric power needed to open the valve during an accident. The Unit 3 RCO alertly noticed that the position indicator light was off and took immediate actions to identify the problem. The PSN-N was notified and the most probable cause of the breaker being opened was due to painting personnel working in the area. The licensee was in the process of upgrading the material condition of the Auxiliary Building. The MCC, in which the breaker is located, was in the vicinity of where painting was in progress. The breaker was closed and the PSN counseled the painting crew. The breaker for the redundant safety injection valve 4-843B was closed during this time, therefore, a flow path to the cold legs was available. Technical Specifications, Section 3.4, allows any valve in the Safety Injection System to be inoperable for a period of twenty four hours. The licensee determined that this valve was inoperable for only a short period of time based on control board walkdowns performed by each oncoming RCO. The inspectors noted a concern to licensee management regarding logbook entries of significant operating events. The APS-N logbook is routed each morning to plant management for review. The APS-N logbook normally contains the significant operating events and occurrences. In this instance, however, this event was not entered into the APS-N logbook and therefore licensee management was not aware of the incident. The licensee made a Night Order book entry on August 30, 1989, to require the PS-N to review the RCO logbooks to ensure that all significant events were logged and that the information is included

in the APS-N logbook for management review. Also, it was noted that the Unit 3 RCO's recognition of the loss of valve position indication and actions taken were commendable.

No violations or deviations were identified in the areas inspected.

9. 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.

On August 23, 1989, with Unit 4 at 100% power, the 4B BATP was declared out of service at 5:15 p.m., due to the seal pot being found empty. The 4A BATP had been out of service since August 9, 1989, therefore, both Unit 4 BATPs were out of service. TS 3.6 specified that three of the four BATPs shall be operable when both Unit 3 and 4 are operating. One pump may be out of service for a period of twenty four hours. TS 3.6 also specified that one flowpath from the boric acid tanks exist to each Unit's RCS. With both Unit 4 BATPs inoperable, a flow path from the boric acid tanks did not exist. When the plant enters a condition prohibited by TS then TS 3.0.1 is applied. This requires the plant to initiate action within one hour to place the unit in a mode in which the specification does not apply. The licensee refilled the 4B BATP seal pot and verified pump flows. The pump was returned to service at 5:48 p.m. that day, therefore, the licensee was not required to commence a unit shutdown.

On August 29, 1989, the licensee reported a significant event to the NRC in accordance with 10 CFR 50.72(b)(1)(v). The control room operators noticed the ENS status light illuminated which indicated a problem with the system. The operators attempted to use the ENS but were unsuccessful. Approximately one minute later the light went out and communications with the NRC was restored. The phone company was notified and was requested to troubleshoot the problem. However, the cause of the failure could not be identified since the system was functioning properly.

On August 31, 1989, with Unit 3 at 100% power, the licensee commenced a load reduction to 75% power due to high vibrations on the 3B FWP. The Analytically Based Preventive Maintenance department had been monitoring the pump vibrations and determined that the 3B FWP vibrations was excessive. The pump was disassembled and cracks were found on the second

stage impeller which were believed to be the cause for the high vibrations. The licensee replaced the entire pump impeller assembly and the pump was tested and returned to service on September 6, 1989. Unit 3 was returned to 100% at 8:00 p.m. that night. The licensee sent the damaged impeller to the vendor for a failure analysis.

On September 5, 1989, at 8:34 a.m., with Unit 4 at 100% power, the licensee noted an indication of high condenser conductivity on strip chart recorder 1400. A unit shutdown was commenced in accordance with 4-ONOP-100 at 8:40 a.m. During the rapid load reduction a turbine runback to 70% was initiated. The runback was caused by an NIS channel detecting a 5% power reduction in less than 5 seconds due to rod insertion and boration to reduce power rapidly. The turbine runback was reported as a significant event in accordance with 10 CFR 50.72(b)(2)(ii). The unit was placed in Mode 2 at 10:38 a.m. The condenser leaks were repaired and the unit returned to service at 7:20 p.m., on September 7, 1989.

On September 10, 1989, with Unit 3 in Mode 1, the 3A BATP was declared out of service at 1:45 p.m. The nitrogen pressure indicator for the BATP seal pot was broken while it was being filled with water. The nitrogen indicator must be removed in order to fill the seal pot. TS 3.6 required a flowpath from the boric acid tanks to the Unit 3 RCS be available. The 3B BATP was aligned to recirculate the B Boric Acid Storage Tank, therefore, when the 3A BATP was declared out of service there was no flowpath from the BASTs to the Unit 3 RCS. Unit 3 entered TS 3.0.1 which allows one hour to restore the flowpath or commence a unit shutdown. The 3B BATP was returned to service at 9:10 p.m. that same day and the unit exited TS 3.0.1. The 3A BATP was returned to service at 9:10 p.m. that day, after gauge replacement and post maintenance testing.

On September 12, 1989, the licensee notified the NRC of a significant event in accordance with 10 CFR 50.72(b)(1)(ii)(B). In April 1989 the stroke of CCW flow control valves CV-3/4-2806, CV-3/4-2807 and CV-8-2808 were reset to yield a maximum CCW flow of 3040 gpm to the ECCs. In January 1989, Procedures 3/4-OSP-055.1, Emergency Containment Cooler Operability Test, were changed to modify the acceptance criteria for CCW flow to the ECCs from greater than or equal to 2000 gpm when the fan is running, to read 2000 gpm to 3040 gpm when the fan is running. This change was initiated in response to a MOS observers comment as an area for improvement. He noticed procedure 3/4-OP-030 specified a maximum flow to the ECCs of 3420 gpm and questioned why 3/4-OSP-055.1 did not have the same limitation. A change to 3/4-OSP-055.1 was then initiated and the CCW valves were subsequently readjusted. In September 1989, a system engineer was reviewing the CCW system history and recognized that the minimum required CCW flow to each ECC might not have been maintained when CCW throttle valves were readjusted. The FSAR, page 9.3-5c, discusses maximum flow considerations for the ECCs and states that operation of the ECCs

with a CCW flow of 3600 gpm up to one week would not impede system integrity and after one week a maximum flow of 3515 gpm would not impede system integrity. TS 4.6.1, Emergency Containment Coolers, states that tests will be performed at each refueling to ensure 2000 gpm minimum water flow through each cooler unit. Individual unit performance will be tested by measuring the temperature differential in the cooling water supply and air stream. FSAR, page 9.3-5a, discusses the design basis of the CCW system and states the most limiting single failure considered was the loss of one diesel, which results in one CCW pump available to mitigate the consequences of the MHA. Although TS and the FSAR discuss a minimum flow of 2000 gpm, it was not clear that this flow was required under accident conditions, i.e., one CCW pump and other alignment changes noted in the FSAR. The Licensing Project Manager in NRR was requested to evaluate the intent of the design basis. The LPM has discussed the basis for the TS with NRC headquarters specialists and the licensee. The intent was not to require the licensee to re-align valves to the accident condition during surveillances but to ensure CCW flow was not inhibited. Based on the licensee's having conducted Unit 3 and Unit 4 CCW system flow balancing tests in 1986, special Test 86-05 and 86-11 respectively, and having documented the position of the flow control valves, no further testing was considered necessary. The licensee readjusted the stroke for the flow control valves on September 12 for Unit 3 and on September 13, 1989, for Unit 4. Procedures have been revised to specify a CCW flow of greater than or equal to 2000 gpm. The licensee evaluated the effect of the valve adjustment on the ECC system and determined that the lowest flow to the 3A ECC would have been 1895 gpm and the remaining coolers would have been greater than 2000 gpm flow during the ECCS injection phase. During the recirculation phase 50 of 6 ECCs would receive less than 2000 grm with a minimum of approximately 1580 grm. In the event of a MHA, the change in containment pressure and temperature would have been very minor with no significant effect on the qualification of equipment inside containment. The inspectors determined that this violation met the criteria specified in Section V.G.I of the NRC Enforcement Policy as a Licensee Identified Violation and will not be cited. This item will be tracked as NCV 50-250,251/89-43-01.

On September 13, 1989, with Unit 4 in Mode 1, the unit entered TS 3.0.1 at 6:50 a.m. due to problems with critical heat tracing circuits. TS 3.6 required that two channels of heat tracing shall be operable for the flowpath from the boric acid tanks to the RCS. TS 3.6 further stated that one channel of heat tracing may be out of service for 24 hours. Upon review of 0-OSP-048.1., Critical Heat Tracing System Operational Test, operations personnel determined that heat tracing circuits 6A and 6B did not meet the acceptance criteria. The failure of both channels of heat tracing resulted in Unit 4 entering TS 3.0.1. This provided an hour to correct the problem before commencing actions to place the unit in a mode in which the specification does not apply. Electrical maintenance repaired circuit 6B and it was returned to service at 10:11 a.m. that day. With circuit 6B in service, Unit 4 exited TS 3.0.1, however, a twenty four hour

LCO existed on the 6A circuit. This circuit could not be restored to service therefore the licensee formed an ERT to investigate the problem.. The ERT determined that the surveillance test performed on the 6A circuit was invalid in that sufficient time was not allowed. At 5:20 p.m. that day, the 6A heat tracing circuit was retested in accordance with 0-OSP-048.1. This test resulted in satisfactory results, therefore, it was concluded that 6A heat tracing circuit was never out of service.

On September 15, 1989, at 12:45 a.m., with Unit 4 at 100% power, an oil leak was discovered on the auto stop oil line to the Unit 4 high pressure turbine left stop valve 4-10-010. The oil leak was coming from a cracked weld in the line and was estimated to be approximately one half to one gallon per minute. Responsible licensee personnel were contacted to develop a suitable method of repair. At 4:26 a.m., the left stop valve went closed due to the oil leak which caused a secondary plant transient. Steam generator pressures increased and levels decreased due to shrink. The running charging pump, 4C, tripped on low speed as it was running back to minimum speed due to increase in T-AVERAGE and swell in pressurizer level. Control rods started stepping in automatically due to T-AVERAGE/ T-REFERENCE mismatch. The NWE noticed that rods stopped stepping in and attempted to drive rods in manually which also failed due to an urgent failure in the rod control system. Due to the failure in the rod control circuitry, a manual reactor trip was initiated at 4:27 a.m. An automatic feedwater isolation was initiated due to low T-AVERAGE and Reactor Trip logic. The RCO noted dual light indication on the "C" steam generator feed regulating valve, FCV-498, indicating the valve had not gone shut and an increasing level in "C" Steam generator. The RCO then placed the controller in manual and FCV-498 was closed. Steam generator "C" level increased to 84% on narrow range and pressurizer level started decreasing due to the cooldown. The RCO started 4A and 4C charging pumps due to a decreasing pressurizer level, however, level could not be maintained and SI was manually initiated at 12% pressurizer level per procedure. No injection occurred as the lowest pressure noted was 1746 psig and injection does not occur until pressure is less than 1588 psig. The plant stabilized and SI was reset at 4:40 a.m. During recovery from the event there were several additional failures which included the following:

- At 5:00 a.m. an oil leak was discovered on "A" EDG. The diesel was secured and declared out of service.

- At 5:50 a.m. the 4B main feed pump tripped when the RO attempted to start the pump.

- At 5:53 a.m. the "A" main feed pump discharge valve (4-MOV-1420) failed to open when starting "A" main feed pump.

- The guarded oil pipe leak detection alarm did not alert operators of the oil leak in the auto stop oil system.

- The sequence-of-events recorder did not function properly for an accurate print out of the event.

Due to the failures both during the event and while recovering from the event an ERT was initiated (ERT-89-018) to determine the root causes and corrective actions required to allow for unit restart.

- Control Rod Drive Malfunction.

  The control rods failed to drive in on Auto or Manual causing the operator to manually trip the reactor. The Automatic Rod Control Speed Signal output to the Rod Control Logic Cabinet was found to be out of specification. The maximum expected voltage should be 9.5 Vdc and it was found to be 10.14 Vdc. This high voltage caused the Rod Control System pulser/oscillator to call for rod speed which was faster than the system capability and a Logic Cabinet Urgent Failure Alarm which halted rod motion as designed. Troubleshooting was performed on the Rod Control Logic Cabinet. The Logic Cabinet was found to be in calibration according to specifications. The output summator, SM-408D, was found to be out of calibration. Westinghouse concurred that the rod speed demand signal from the Process Control System was too high and was the cause for the Urgent Failure Alarm. Calibration of SM-408D was performed and the Rod Control System was tested and the system was found to be operational.

- 4C Charging Pump Tripped on Low Flow Demand.

  The oil pressure switch (PS-4-201C) was found to be out of calibration. Subsequent calibration followed by post maintenance testing determined that the repeatability of the switch was poor. The switch was then replaced and successfully calibrated. Long range plans are to obtain a replacement switch with a narrower range more suitable for this application and relocate the switch away from the pump where it will be less susceptible to vibration.

- Failure of 4A Steam Generator Feed Pump Discharge Valve (MOV-1420) To Open.

  MOV-1420 failed to open upon pump start resulting in the inability to restore normal feedwater flow when recovering from the event. The root cause was determined to be the motor for the MOV was burned out because pressure across the valve was not equalized prior to starting the pump. The bypass valve (4-20-117) around MOV-1420 could not be opened due to the stem to handwheel mating joint having rounded off. Attempting to open the MOV without equalizing the pressure across it resulted in requiring an opening thrust in excess of the existing MOV capacity. This resulted in the MOV motor burning out as the circuitry does not contain overload protection. The bypass

valve(4-20-117) was repaired and the MOV motor was replaced and tested satisfactorily. Although the operating procedure for startup of a feed pump requires the bypass valve (4-20-117) to be open for 30 to 60 minutes to ensure adequate warmup of the pump, the PS-N directed that the pump be started. This decision was based on the fact the pump was sufficiently warm prior to the start due to the long period of at power operation prior to the pump trip and that O-ADM-201, Upgrade Operations Procedure Usage, provides specific latitude to allow the PS-N to evaluate the situation and determine if the procedure may be continued when a procedure step cannot be completed as written.

- 4B Steam Generator Feed Pump Failure to Start.

  During the event the 4B feed pump failed to start on two occasions. The DDPS printout indicated the first attempt failed as the feedwater isolation signal was still present and the circuity functioned as designed. A definite root cause for the second failure to start could not be determined as the pump was successfully started at 10:17 a.m. that morning on the third attempt. Subsequent testing of the breaker identified no problems. The licensee considered the second failure to start may have been attributed to a permissive problem in the start interlock pressure switch (PS-4-2031) and the start lube oil pressure switch (PS-4-2051). The sensing lines to these switches were cleaned and the pressure switches were calibrated. The cause of this failure is still under investigation by the licensee as a specific root cause could not be identified.

- Valve FCV-4-498, "C" Steam Generator Feed Regulating Valve, Failure Resulting in a High Steam Generator Level.

  Valve FCV-4-498 was slow to close after initiation of the "20 second" closure signal resulting in a high level in "C" steam generator. The "20 second" solenoid valve was removed and tested. Testing revealed that the valve did not totally "switch states", i.e., there was air coming out of all three ports. The more the valve was cycled, the fewer failures were experienced. Further inspections found foreign material in the valve. The valve was tested and disassembled by the manufacturer, (ASCO). In addition to the foreign material, gouges and scratches in the area of the lower stem were observed. ASCO stated that foreign material in the valve could cause this type of failure. The lines and actuators for all three Feed Regulating Valves were cleaned, inspected, and blown down. The failed solenoid valve, SV-4-498B, was replaced and testing was conducted on all three FCVs.

- Turbine Oil Leak.

This item was the initiator of the event caused by a cracked weld in the auto stop oil to the Left Hand Turbine Stop Valve causing the valve to shut. The cracked weld was cut out and replaced. Post maintenance testing was performed satisfactorily and all other accessible oil line welds were visually inspected.

- Guarded Oil Pipe Leak and Failure of Guarded Oil Pipe Alarm.

  The guarded oil pipe surrounds the high pressure oil pipes to the stop and control valves to contain any leakage of high pressure oil and direct it back to the reservoir. The guarded oil pipe is equipped with an alarm actuated by a pressure switch to notify the operators there is a leak inside the guarded oil piping. During this event the alarm did not function and oil leaked out of a slip joint and a crack on a weld at an elbow of the guarded oil plenum. The cracked weld was repaired and no action was required for the slip joint as it is required to allow for thermal expansion. The lines to the guarded oil plenum pressure switches for both units were cleaned and flushed and the pressure switches were calibrated and tested satisfactorily.

- "A" Emergency Diesel Generator Oil Hose Rupture.

  During the SI actuation the EDGs started as required. When the turbine operator arrived at the "A" EDG, at about 5:00 a.m., he noticed an oil leak of approximately 1/2 gpm coming from a lube oil hose connected to the lube oil low pressure switch in the control cabinet. The hose was replaced and all other hoses for both EDGs were inspected and found to be satisfactory.

- Sequence of Events Reporting was Inaccurate During the Event.

  During the event the DDPS equipment was being powered by an unregulated, alternate power supply from Unit 4 rather than by its normal inverter. Power surges caused a Switched Peripheral Controller, a device to switch between two processors, to switch to the wrong processor causing data to be lost. The power supply for the DDPS cabinets was realigned to the DDPS inverter. The static transfer switch for DDPS power was labeled with: CAUTION IF DDPS POWER TO REMAIN ON ALTERNATE SOURCE GRATER THAN 8 HRS. NOTIFY THE DDPS COORDINATOR. The DDPS inverter was labeled with: NOTIFY THE DDPS COORDINATOR PRIOR TO REMOVING THE DDPS INVERTER FROM SERVICE FOR MAINTENANCE. Any maintenance requiring the removal of the DDPS inverter from service will be reported as a Hot Item during the morning meeting.

Subsequent to the event the licensee opted to cool the unit down to Mode 5 to facilitate repairs to some components not associated with the trip including; replacement of defective wiring in the Unit 4 turbine control system, troubleshooting RPI G-3, and repair of steam generator blowdown

valve SGB-4-001. The unit entered Mode 5 at 8:30 a.m. on September 23, 1989.

On September 20, 1989, with Unit 4 in Mode 3, a plant electrician was seriously injured when a valve stem was ejected and hit him in the jaw. Maintenance personnel were reassembling the motor operator for motor operated valve (MOV) 4-1420, 4A SGFP discharge isolation valve. The valve operator motor burned out when operators attempted to open the valve after the September 15, 1989, Unit 4 manual trip and safety injection (discussed previously). After replacing the motor, maintenance personnel determined that the actuator had a broken drive sleeve. The actuator was disassembled and the drive sleeve was replaced. In order to force the stem nut down to the valve stem, the nut must be threaded onto the stem until it contacts the drive sleeve splines and then the handwheel must be turned in the open direction. It was during this step that the valve stem moved up causing the valve to unseat. The feedwater line was pressurized to approximately 1000 psig. The feedwater pressure forced the stem up and it struck the electrician. Review of the event indicated that the clearance (number 4-89-09-069) was inadequate for the work being performed. The original work scope was changed from troubleshooting to MOVATS testing and subsequently to replacing the defective drive sleeve. The original clearance boundary had the 4A SGFP suction isolation valve and suction bypass valve closed. The downstream isolation valves for 4-1420 were open, therefore, the line was pressurized since the licensee was operating a Standby Steam Generator Feedwater Pump to feed the steam generators. After this event the 4B SGFP was added to the clearance in addition to valves downstream of 4-1420 and 4-1421 (B SGFP discharge isolation MOV). These actions adequately isolated 4-1420 for work to continue. TS 6.8.1 requires that written procedures and administrative policies shall be established, implemented and maintained that meet or exceed the requirements and recommendations of Appendix A of NRC Regulatory Guide 1.33 and Sections 5.1 and 5.3 of ANSI N18.7-1972.

Administrative Procedure (AP) 0103.4, In-Plant Equipment Clearance Orders, dated July 27, 1989, specified that In-Plant Equipment Clearance Orders shall be required for the safety and protection of plant personnel and equipment However, clearance number 4-89-09-069 was inadequate on September 20, 1989, in that MOV-4-1420 was not fully isolated. This allowed the line to remain pressurized which caused the valve stem to be ejected resulting in serious injury to a plant electrician. This item will be tracked as violation 50-250,251/89-43-03.

10. Management Meeting

This meeting was held on September 19, 1989, and was the thirteenth in a series of management meetings between the NRC and FP&L following the issuance of Confirmatory Order 87-85 in October 1987. The previous meeting was held on July 19, 1989. A plant tour was conducted by the resident inspectors to update NRC Management on plant conditions. The licensee made presentations on the status of the Independent Management Assessment program, QA/QC contributions to plant improvement, status of

maintenance, nuclear engineering program status, security status and an overall facility evaluation.

11. Exit Interview (30703)

The inspection scope and findings were summarized during management interviews held throughout the reporting period with the Plant Manager - Nuclear and selected members of his staff. An exit meeting was conducted on September 29, 1989. The areas requiring management attention were reviewed. No proprietary information was provided to the inspectors during the reporting period. The inspectors had the following findings:

50-250,251/89-43-01, Non Cited Violation. Adjustment of CCW flow control valves that reduced flow to one ECC below design setpoint. (paragraph 9)

50-250,251/89-43-02, Inspector Followup Item. Implementation of procedural change to ensure only qualified operators assume shift duties. (paragraph 8)

50-250,251/89-43-03, Violation. Inadequate clearance resulting in disassembly of a valve in a pressurized system. (paragraph 9)

12. Acronyms and Abbreviations

ADM	Administrative
AFW	Auxiliary Feedwater
ANSI	American National Standards Institute
AP	Administrative Procedures
APS-N	Assistant Power Supervisor Nuclear
ASME	American Society of Mechanical Engineers
ASP	Auxiliary Shutdown Panel
BAST	Boric Acid Storage Tank
BATP	Boric Acid Transfer Pump
CCW	Component Cooling Water
CCTV	Closed Circuit Television
CFR	Code of Federal Regulations
CS	Containment Spray
DDPS	Digital Data Process System
DP	Differential Pressure
ECC	Emergency Core Cooler
ECCs	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ENS	Emergency Notification System
ERT	Event Response Team
FPL	Florida Power & Light
FSAR	Final Safety Analysis Report
FNP	Feedwater Pump
HHSI	High Head Safety Injection
ICW	Intake Cooling Water

IEB	Inspection and Enforcement Bulletin
IFI	Inspector Followup Item
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LIV	Licensee Identified Violation
LOCA	Loss of Coolant Accident
MCC	Motor Control Center
MHA	Maximum Hypothetical Accident
MP	Maintenance Procedures
MOS	Management on Shift
MOV	Motor Operated Valve
NCR	Non-conformance Report
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NNE	Nuclear Watch Enngineer
ONOP	Off Normal Operating Procedure
OOS	Out of Service
OTSC	On the Spot Change
PA	Protected Area
PC/M	Plant Change/Modification
PNSC	Plant Nuclear Safety Committee
PRM	Process Radiation Monitor
PSP	Physical Security Procedures
QA	Quality Assurance
QC	Quality Control
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RO	Reactor Operator
SI	Safety Injection
SGFP	Steam Generator Feedwater Pump
SRO	Senior Reactor Operator
TS	Technical Specification
TSA	Temporary System Alteration
URI	Unresolved Item