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

Report Nos.: 50-250/88-30 and 50-251/88-30

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: September 26, 1988 through October 28, 1988

Inspectors: William K. Poertner for 11/18/88
R. C. Butcher, Senior Resident Inspector Date Signed

William K. Poertner for 11/18/88
T. F. McElhinney, Resident Inspector Date Signed

William K. Poertner for 11/18/88
G. A. Schnebli, Resident Inspector Date Signed

Approved by: 11/23/88
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 surveillance observations, maintenance observations, engineered safety features, operational safety verification, facility modifications and plant events.

Results: In the areas inspected, one violation with two examples was identified, 88-30-03, failure to maintain an audible neutron flux monitor in the control room as required by Interim Technical Specifications; and use of an improper procedure to make up to the refueling cavity.

One Licensee Identified Violation is discussed in this report concerning the failure to report within the required time that both Emergency Diesel Generators were out of service at the same time.

The inspectors expressed a concern regarding the adequacy of reactor refueling cavity and spent fuel pit water level indication in the control room in relation to procedural requirements. Improved operator aids/information appears desirable.

The inspectors also expressed concern regarding the adequacy of drawings, especially in light of the recent plant events related to drawing deficiencies.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

B. A. Abrishami, System Performance Supervisor
J. W Anderson, Quality Assurance (QA) Supervisor
*J. Arias, Regulation and Compliance Supervisor
*L. W. Bladow, Quality Assurance Superintendent
*J. E. Cross, Plant Manager-Nuclear
R. J. Earl, Quality Control (QC) Supervisor
*J. D. Evans, Site Document Control Supervisor
T. A. Finn, Training Supervisor
*D. D. Grandage, Configuration Management
*K. Gross, Compliance Engineer
S. Hale, Engineering Manager
*P. S. Harpel, Operations
R. D. Hart, Regulation and Compliance Engineer
J. W. Kappes, Maintenance Superintendent
V. A. Kaminskas, Reactor Engineering Supervisor
J. A. Labarraque, Senior Technical Advisor
R. G. Mende, Operations Supervisor
*J. S. Odom, Site Vice President
L. W. Pearce, Operations Superintendent
*W. E. Raasch, System Engineer
*F. H. Southworth, Technical Department Supervisor
J. C. Strong, Mechanical Department Supervisor
*E. A. Suarez, Configuration Control
D. Tomaszewski, Instrument and Control (I&C) Department Supervisor
*G. A. Warriner, Quality Operations Supervisor
M. B. Wayland, Electrical Department Supervisor
J. D. Webb, Operations - Maintenance Coordinator
W. R. Williams, Jr., Acting Maintenance Superintendent
*A. T. Zielonka, Nuclear Engineer

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

*Attended exit interview on October 28, 1988.

2. Unresolved Items (URI)

Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations of requirements or deviations from commitments. No unresolved items were identified in this report.

3. 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:

O-OSP-023.1 Emergency Diesel Generator Operability Test

No violations or deviations were identified in the areas inspected.

4. 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:

- Repair of 3B Safety Injection Pump.
- Repair of Unit 3 Pressurizer Heaters/Cables.
- Installation and Testing of Unit 4 Cavity Seal.

- Preparations for Unit 4 Refueling.
- Replacement of 3A RCP Seals.
- Corrective Actions for Failure of Unit 3 PORV 455C.
- Replacement of 3A RHR Pump Seal.

a. On September 20, 1988, at 10:45 p.m., with Unit 3 at 100% power and Unit 4 in Mode 4, the "A" Emergency Diesel Generator (EDG) was declared out of service (OOS) due to the fuel oil pressure exceeding the acceptance criteria specified in 0-OSP-023.1, Diesel Generator Operability Test. The "A" diesel was being tested daily per the OSP as required by TS as the "B" diesel was OOS for maintenance. The fuel oil pressure after starting indicated 41 psig which exceeded the upper limit of 40 psig specified in the acceptance criteria of the OSP. The plant was placed in TS 3.0.1 and preparations were made to perform a Unit 3 shutdown in accordance with 3-GOP-103. A plant work order (PWO) was submitted to replace the fuel oil filters on the "A" diesel which was completed and the diesel was tested and returned to service at 2:35 a.m. on September 21, 1988.

Although the fuel oil pressure limit of 40 psig was exceeded, this was only during the initial start. The pressure stabilized at 35 psig after the initial start. After filter changeout the pressure initially indicated 29 psig and stabilized at 23 psig. The vendor technical manual states the fuel oil pressure should run between 20-50 psig with maximum limits of 10-65 psig. Although the licensee's specified acceptance criteria and actions to place the unit in TS 3.0.1 were conservative, two areas of concern were identified as follows:

(1) The EDG is equipped with a duplex fuel oil filter such that filter changeout can be accomplished while the diesel is running. The control valve which determines which filter is in service has three positions, "L" (left), "Both", or "R" (right) and is normally selected to "Both". To change a filter, the control valve selector lever is moved to the letter ("L" or "R") representing the opposite filter which places that filter in service. The filter to be changed is then replaced and the selector lever returned to "Both" or the process repeated for the opposite filter. However, due to packing leakage at the filter selector shaft, the packing has been excessively tightened such that the selector lever cannot be moved from the "Both" position. Therefore, in order to change a filter the EDG must be placed out of service or the packing loosened to allow movement of the selector lever which may pose a fire hazard due to the leakage. The licensee stated that packing for the selector levers on both EDGs would be replaced during repairs to

the EDGs while in the current Unit 3 forced outage and the Unit 4 refueling outage. In addition, 0-OSP-023.1, and other EDG procedures would be modified to specify acceptable ranges for fuel oil pressure and corrective action to be taken prior to placing the EDG out of service and possible entry into TS 3.0.1. This is identified as Inspector Followup Item 50-250,251/88-30-01.

(2) The other area of concern was that this event occurred on September 20, 1988, and was reportable in accordance with 10 CFR 50.72 (b)(1)(ii)(B), as operating the plant with both diesel generators out of service is a condition that is outside the design basis of the plant. However, even though the licensee took the proper action by placing the plant in TS 3.0.1, the required one hour report was not made until October 14, 1988. This was identified by the licensee during the review of a draft copy of an LER concerning this event which was being written to comply with 10 CFR 50.73 (a)(2)(i). The inspectors consider missing the one hour notification to be an isolated case as the licensee is usually timely in this respect.

The issue discussed above constitutes a violation of 10 CFR 50.72(b)(1)(ii)(B) in that the event was not reported within one hour of the event. However, because the NRC wants to encourage and support licensee initiative for self-identification and resolution of problems, the five tests delineated in 10 CFR 2, Appendix C, were applied. Discussions between the resident inspectors and regional management were held and it was determined this violation meets the criteria of 10 CFR 2, Appendix C, therefore, no notice of violation will be issued.

b. On October 2, 1988, with Unit 3 in Mode 4, the licensee was testing the backup Overpressure Mitigation System (OMS) loop, in accordance with 3-OP-041.4, prior to placing the system in service. Power Operated Relief Valve (PORV) 3-455C failed to open and was declared out of service and a PWO was issued. Troubleshooting identified that the diaphragm which operated the PORV was leaking air around the edges and the cap screws were loose. The cap screws were subsequently retorqued, the test was reperformed and the valve returned to service. The licensee performed a root cause analysis, which was reviewed by the inspectors, and determined that the most probable cause was the diaphragm material. The licensee considered the leakage was caused by the diaphragm losing thickness due to the heat or the cap screws loosening around the actuator due to excessive vibration. Excessive vibration was ruled out as a root cause because no other components associated with the PORV experienced failure due to vibration. However, as a precautionary measure, the licensee plans to install lockwashers on the cap screws to preclude loosening by vibration.

The PORVs installed at the plant are Copes-Vulcan with the actuator diaphragm made of Buna-N. This material is rated for a maximum temperature of 250 degrees F. Discussions with the vendor indicated a diaphragm constructed of ethylene-propylene (EP) may be more suitable for this application as the EP material is rated to 350 degrees F. The licensee has installed EP diaphragms in the PORVs. Followup on the success of the corrective actions will be identified as IFI 50-250,251/88-30-02.

No violations or deviations were identified in the areas inspected.

5. 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 were 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

a. The licensee contacted the resident inspectors in regard to removing an Emergency Diesel Generator (EDG) from service while in operational modes 5 and 6. The resident inspectors, Region II management, and the NRC project manager discussed TS requirements and it was concluded that TS permitted the removal of an EDG during operation in Modes 5 and 6. Beyond TS requirements, the NRC expressed concern to

licensee management regarding the removal of an EDG when a shut down unit is in a drain down configuration, such as mid-nozzle water level for reactor coolant pump maintenance, due to industry concerns that have been recently identified. Licensee management made the commitment that during the existing drain down of Unit 3, two reliable sources of shutdown cooling would always be available. This requires that when the reactor coolant system has been drained down in either Modes 5 or 6, two loops of shutdown cooling will remain available. This can be accomplished by relying on two residual heat removal pumps with two EDGs operable and associated intake cooling water and component cooling water pumps (one per train). An EDG can be taken out of service once the unit is filled and vented. The licensee intends to operate within this restriction until implementation of the resolution of a pending Generic Letter regarding the loss of shutdown cooling due to air binding of residual heat removal pumps and the potential for uncovering the fuel while in a drain down configuration.

b. The resident inspectors reviewed the Management On Shift (MOS) report for October 6, 1988, and noted comments regarding an operators lack of commitment to following procedures. The residents noted that although both units were shutdown, the lack of procedural adherence is unacceptable. The residents expressed their concern to licensee management and were assured that actions were being taken to correct the noted problem. The plant manager held meetings with every oncoming operations shift to discuss management's position that failure to follow procedures would not be tolerated and discussed the standards that operations personnel are required to meet. The residents attended some of the briefings and noted positive response from operations personnel. Subsequent observations by the same MOS observer, indicated that management's meetings with operations personnel resulted in a positive attitude and procedural adherence was observed during subsequent operations. Licensee management also plans to incorporate followup checks to ensure procedural adherence and management will be on shift during unit startup.

c. The reactor vessel drain down level indication in the control room (LI-4-6421) has a scale from 0 to 100%. Mounted on the panel next to LI-4-6421 is a placard relating the indicator reading to the reactor vessel flange level. This allows the operators to correlate instrument readings to the procedural reactor vessel level requirements when drained down, i.e., 4-OP-041.7, Draining the Reactor Coolant System, requires reactor coolant system water level be maintained within 2 feet 6 inches to 3 feet 6 inches below the reactor vessel flange. The spent fuel pit level indicator in the control room (LI-4-651) has a scale from +9 inches to -27 inches. The instrument increments are each worth 2.25 inches. Operating procedure 4-OP-201, Filling/Draining the Refueling Cavity and the SFP Transfer Canal, paragraph 7.2, refers to levels such as 56 feet 10 inches but nothing is available to help the operators correlate

LI-4-651 readings to 56 feet 10 inches in the spent fuel pool. Also, when the SFP transfer canal is isolated, the only indication for refueling cavity water level in the control room is the pressurizer level cold calibration instrument LI-4-462. LI-4-462 has a scale from 0 to 100%. No information is readily available to the operators (except for memory) to correlate level reading in the pressurizer to actual refueling cavity water level. It appears that an operator aid, such as is available for the reactor vessel drain down level indicator, would be desirable to insure the spent fuel pit level indicator and the pressurizer cold calibration level indicator provide meaningful indication to the operators to relate the various water levels called out in procedures.

d. On October 13, 1988, the inspectors questioned the Unit 4 RCO as to why the audible count rate was not on in the control room. The RCO responded that the containment is required to have an audible indication but the control room only required visual indication. Technical Specification 3.10.3, Refueling Operation Instrumentation, specifies: As a minimum, two Source Range Monitors shall be OPERABLE, each with continuous visual indication in the control room and one with audible indication in the containment. This TS is applicable in Mode 6. However, the licensee's Interim Technical Specification (ITS) 3/4.9.2, specifies that an audible neutron flux monitor shall be OPERABLE in the containment and control room when in Mode 6.

The licensee developed ADM-021, Technical Specification Implementation Procedure, revision dated September 29, 1988, which provides a transition from the existing TS to the Revised Technical Specifications (RTS). The RTS are in the process of being reviewed by the NRC and FPL. ADM-021 requires plant personnel to comply with the ITS unless the requirements are waived in accordance with the procedure or are less restrictive than the current TS. The waiver must be approved by the Operations Superintendent and Plant Manager-Nuclear Due to the ITS being more restrictive than the existing TS, the operators were required to request a waiver for ITS 3/4.9.2. However, the operator silenced the audible neutron flux monitor in the control room prior to requesting a waiver. Although the licensee was licensed to the existing TS, the ITS are controlled and followed by an approved plant procedure. TS 6.8.1, specifies that written procedures and administrative policies shall be established, implemented and maintained that meet or exceed the requirements and recommendations of Section 5.1 and 5.3 of ANSI N18.7-1972.

Section 5.1.2 of ANSI N18.7-1972, specifies that procedures shall be followed. ADM-012, revision dated September 29, 1988, requires plant personnel to comply with the ITS unless the requirements are less restrictive than existing TS or the requirements are waived by the Operations Superintendent and Plant Manager-Nuclear. ITS 3/4.9.2 requires, in Mode 6, that an audible neutron flux monitor be operable in the control room and containment.

Contrary to the above, on October 13, 1988, with Unit 4 in Mode 6, the audible neutron flux monitor in the control room was silenced by operations personnel without obtaining a waiver. This item is the first example of violation 50-250,251/88-30-03.

6. 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 September 23, 1988, at 9:15 am, the B Emergency Diesel Generator (EDG) failed to start when the control room start push button was pushed. The operators cycled the local/normal/off switch and the EDG started on the next try. The licensee's trouble shooting on the EDG indicates that the local/normal switch contacts might not have made up to complete the start circuitry. The licensee could not duplicate the event. Procedures have been revised to require that the control room start pushbutton switch contacts be checked for continuity every time the B EDG is to be started. It is considered likely that a contact briefly lost continuity but the cycling of the switch wiped the contact clean and the problem will not recur.

At 1:30 am, on September 26, 1988, the licensee found that the Unit 3 Steam Generator (SG) blowdown sample flow to Process Radiation Monitor System (PRMS) 19 for SG A,B and C was isolated. The licensee initially determined that manual valves 20-3-530, 531, 532, and 534 were closed. Operations immediately isolated the SG blowdown by closing CV-3-6275A, B and C. The licensee notified the NRC per 10 CFR 50.72(b)(2)(iii)(C). After re-establishing proper sample line valve lineup to monitor the SG blowdown, SG blowdown was re-established. TS table 3.9-2, Radioactive Liquid Effluent Monitoring Instrumentation, Item 1.b, requires a minimum of one channel of a gross radioactivity monitor which provides for automatic termination of the release from the SG blowdown effluent line. With less than one operable channel, action item 2, requires effluent releases be sampled at least once per 12 hours or 24 hours, depending on the specific activity level in the secondary coolant. PRMS-19 automatically isolates the SG blowdown on a high radiation signal.

Subsequent investigation by the licensee indicates that the SG blowdown sample flows to PRMS 19 were possibly not isolated but that isolation valves 20-3-530, 531 and 532 were actually in the throttled position. The movement on the valve handle to obtain the required 5 gph sample flow is

so slight that the operator might have thought the valve was closed while it was actually being used as a throttle valve. The licensee did not have procedures to control the operation of the valves and the throttle and isolation valves are in series and very close to one another.

The licensee's investigation into the loss of flow indication in the Unit 3 steam generator blowdown sample line had the following conclusions.

- The sample lines were plugged, blocking flow to PRMS-19.
- The isolation valves were not closed but were slightly open and being utilized as throttle valves. The small flow rate of 5 gph makes it difficult to easily distinguish this position from the closed position.
- There were no procedures which established the work controls for the operation of the isolation and/or throttle valves.
- Some throttle valves were well off the seat of the valve indicating they were not being used as throttle valves.
- The chemistry department was taking grab samples from the SGs daily, due to their lack of knowledge about the status of PRMS-19.

TS table 3.9-2, requires one channel of a gross radioactivity monitor providing automatic termination of release from the SG blowdown effluent line. Action statements allow effluent releases to continue provided grab samples are analyzed for gross radioactivity at least once per 24 hours when the specific activity of the secondary coolant is ≤ 0.01 uCi/ml dose equivalent I-131. Since the licensee's sampling program met the requirements of TS table 3.9-2, no TS violation occurred.

The licensee determined the following root causes:

- The design of the system is less than adequate.
- The blowdown system is designed to remove solids. The blowdown sample function requires low flowrates which results in small valve openings that frequently plug due to particulates in the process stream.
- Human factors considerations in the design of the piping and valves were lacking.
- No program was in place to ensure TS requirements for PRMS-19 were being routinely met. Mitigating this was that Chemistry was performing the TS actions by sampling the steam generators daily.

- Work controls were less than adequate in that neither management nor plant personnel surfaced the fact that procedural guidance was lacking for the manipulation and setting of these valves.

The inspectors will followup on the licensee's corrective actions and recommendations as Inspector Followup Item 50-250,251/88-30-04.

On September 29, 1988, at 1:59 am, with Unit 3 in Mode 1, the RCO received an annunciator indicating Auxiliary Feedwater (AFW) nitrogen backup supply station 1, Train 1, low pressure. Train 1 of Unit 3 AFW was declared out of service and a Plant Work Order (PWO) was initiated. The AFW Flow Control Valves (FCVs) are air actuated and provided with a nitrogen backup supply in the event of a loss of instrument air. The licensee determined that a clearance hung on Unit 4 instrument air isolated the air supply to the Unit 3 Train 1 AFW FCVs. The clearance was partially released which restored air to the FCVs. The nitrogen bottles were replaced and Unit 3 Train 1 AFW was declared back in service at 5:00 am that day. The licensee's investigation of this incident revealed that the instrument air drawing, 5610-T-E-4064, sheet 2, was inadequate. The clearance issued for Unit 4 isolated valve 4-735. The drawing showed that this would isolate air to a line shown as "to turbine area" through valve 4-737. The drawing did not show, however, that this line continued on drawing 5610-T-E-4064, sheet 3. This line went to the Unit 3 AFW Train 1 FCVs. The licensee determined that the low pressure alarm was due to leaking check valves. This was the cause of the nitrogen low pressure as the nitrogen leaked by check valves 4-811 and 4-815. The licensee repaired the check valves and declared Train 1 AFW back in service on October 1, 1988, at 9:30 am. The licensee also submitted a Request for Engineering Assistance (REA) 88-471 to correct drawing deficiencies for the instrument air system. This change will correct the problem associated with the AFW FCVs, however, the Instrument Air System drawings still need to be updated to reflect the entire system configuration. This is the first example of IFI 250,251/88-30-05.

On October 1, 1988, during Inservice Testing (IST) on the 3A Residual Heat Removal (RHR) pump, the seal leak off was greater 150 drops/minute, which exceeded the acceptance criteria of 100 drops/minute and the licensee declared the pump inoperable. TS 3.4.1.b.4, allows one RHR pump to be out of service provided it is restored to operable status within 24 hours. The licensee stated that replacement of a RHR pump seal would take greater than 24 hours and therefore Unit 3 was shut down at 9:40 pm on October 1, 1988. This shutdown was reported to the NRC per 10 CFR 50.72 (b)(1)(i)(A). Following the shutdown, a question was raised as to what equipment could be out of service before the licensee would enter TS 3.0.1. At the time RHR pump 3A failed the IST, the 3B Safety Injection (SI) pump was also out of service. TS 3.4.1.b, states in part "During power operation, the requirements of 3.4.1.a, may be modified to allow one of the following components to be inoperable (including associated valves and piping) at any one time except for the cases specified in 3.4.1.b.2.

(1) ONE accumulator may be out of service for a period of up to 4 hours.

(2) ONE of FOUR safety injection pumps may be out of service for 30 days. A second safety injection pump may be out of service, provided the pump is restored to operable status within 24 hours. TWO of the FOUR safety injection pumps shall be tested to demonstrate operability before initiating maintenance of the inoperable pumps.

(3) ONE channel of heat tracing on the flow path may be out of service for 24 hours.

(4) ONE residual heat removal pump may be out of service, provided the pump is restored to operable status within 24 hours. In addition, the other residual heat removal pump shall be tested to demonstrate operability prior to initiating maintenance of the inoperable pump.

(5) ONE residual heat exchanger may be out of service for a period of 24 hours.

(6) Any valve in the system may be inoperable provided repairs are completed within 24 hours. Prior to initiating maintenance, all valves that provide the duplicate function shall be tested to demonstrate operability.

(7) To permit temporary operation of the valve, e.g., for surveillance of valve operability, for the purpose of valve maintenance, etc., the valves specified in 3.4.1.a.7 may be unlocked and may have supplied air or electric power restored for a period not to exceed 24 hours.

The residents requested regional assistance in interpreting TS 3.4.1.b. Regional management contacted the NRR Project Manager and the TS interpretation was that each of the items noted could be out of service concurrently, for example, one accumulator, two safety injection pumps and one RHR pump could be out of service concurrently as long as each individual time limit was not exceeded. This interpretation was conveyed to the licensee.

On October 6, 1988, a mechanic was contaminated with a hot particle while working on the Unit 3 containment equipment hatch. The contamination was discovered when the mechanic was frisking after exiting the containment. The mechanic was taken to the decon room where the hot particle was removed and saved for analysis. Initial gamma analysis by the licensee revealed that almost 97% of the particle activity was composed of CO-60 (83.7%) and Mn-54 (13.2%). Based on the licensee data, the initial estimate of the skin dose to the worker was between 7.18 rem and 11.15 rem. The calculations were based on a conservative estimate of exposure

time and was not corrected for any possible self absorption of betas within the hot particle. The licensee contracted Battelle Pacific Northwest Laboratory to perform an evaluation of the hot particle and an official skin dose calculation. The licensee notified Region II health physics personnel of this event.

On October 11, 1988, the Plant Supervisor-Nuclear (PSN) Shift Report documented a situation involving containment refueling integrity for Unit 4. The licensee had performed 4-OSP-051.12, Refueling Containment Penetration Alignment. This procedure provides instructions to align the containment penetrations for refueling. The PSN reported that during the performance of 4-OSP-051.12, a test rig was found installed on valve 4-285A with the valve open and uncapped. Also, five valves were in a different position since the last performance of 4-OSP-051.12, the previous week. Another entry in the Shift Report indicated that several discrepancies were noted between what was in the field versus the drawings, procedures and valve index during a walkdown of the Component Cooling Water (CCW) inside containment going to and from the Emergency Containment Coolers (ECCs). Due to these problems, licensee management decided to delay the Unit 4 core off-load in order to walkdown all containment penetrations. The walkdowns were performed using the appropriate plant procedures and drawings for each of the 84 penetrations. These documents were also reviewed against the Final Safety Analysis Report (FSAR) to ensure that all containment penetrations were identified for the walkdown. In order to help maintain positive control of valve position for refueling integrity, clearances were generated for each penetration, and hung in the field. The Plant Nuclear Safety Committee (PNSC) defined refueling integrity such that there shall be no direct path from containment atmosphere to the environment. The refueling integrity procedure, 4-OSP-051.12, was revised to reflect the as built configuration of each penetration, which ensures compliance with the refueling integrity definition. The walkdown teams also attached permanent yellow containment isolation tags for each valve identified as part of refueling integrity. Pink discrepancy tags were hung on valves that did not have an identification tag or were not shown on the T-E drawing. The walkdowns were performed using a checklist with independent verification signoffs required. The walkdown identified two valves that were in the open position. Penetration 6, valve 4-550 and penetration 26B, POV-2605 (B MSIV). The MSIV was found to be in the midposition. Since the reactor vessel head was removed on October 7, 1988, and the upper internals were removed on October 10, 1988, the inspectors question whether refueling integrity existed during these core alterations. The licensee was in the process of resolving this issue at the end of this inspection period and this item will be addressed in the next resident monthly Inspection Report. The licensee generated REAs to address the discrepancies between the as built configuration and the T-E drawings. The licensee also formulated a plan to walkdown the Unit 3 penetrations prior to restart from the unplanned outage scheduled to end in mid November. This is the second example of IFI 250,251/88-30-05.

On October 13, 1988, at 10:40 am, the licensee reported to the NRC that engineering review and analysis of the emergency diesel generator load analysis identified a potential single failure which could impact the ability of the plant to respond to a design basis accident. There are three Intake Cooling Water (ICW) pumps for each unit. The A ICW pump is powered from the A Emergency Diesel Generator (EDG) and the B and C ICW pumps are powered from the B EDG. In the event of a loss of offsite power, the A and B ICW pumps would be automatically loaded onto the A and B EDGs, respectively, by the load sequencer. If the A ICW pump were to trip on overcurrent and the B ICW pump was operating, the auto start logic would cause the C ICW pump to be started and loaded onto the B EDG. This additional loading of the B EDG could cause an EDG loading problem. This condition would only occur if a design basis accident occurred where large safeguards pumps were loaded on the EDGs. The licensee's immediate corrective action was to rack out the breakers for the C ICW pump to prevent auto start. Long term corrective actions by the licensee will be followed up as Inspector Followup Item 50-250,251/88-30-06.

On October 15, 1988, with Unit 4 in Mode 6 and fuel in the reactor, the RCO noted a Spent Fuel Pool (SFP) low level alarm and attempted to raise the refueling cavity level. The RCO used the Boric Acid Transfer Pumps (BATP) from the Boric Acid Storage Tanks through the charging pump suction. Although the charging pumps were not operating, there was enough head pressure from the Volume Control Tank (VCT) to inject the acid into the Reactor Coolant System (RCS). During this evolution the RCO noticed the boric acid flow rate was at zero. Apparently the high concentration of acid (20,000-22,500 parts per million) combined with the low flow (20-30 gallons per minute) caused the charging line to clog. The operators started a charging pump to re-establish a flowpath. The charging pump discharge pressure reached approximately 600 psig before the line unclogged.

This event was mentioned in the Management On Shift (MOS) report, dated October 16, 1988, as an area for improvement. The licensee's investigation focused on why the RCO used boric acid to raise the refueling cavity level when he could have used either normal blend or the Refueling Water Storage Tank (RWST).

The Nuclear Watch Engineer (NWE) had requested the RCO to makeup to the cavity using normal blend and told the RCO to use his procedures. However, ADM-021, Interim Technical Specification Implementation Procedure, revision dated September 29, 1988, section 3/4.9.1, requires that primary water supply to the boric acid blender be verified closed and in a secure position by mechanical stops or by removal of air or electric power at least once per 31 days. Therefore, valve 4-114A, primary water to the blender station, was isolated on a clearance, per procedure 4-OP-038.1, Preparation for Refueling Activities. The RCO did not realize that the night orders allowed a partial release of the clearance to allow for makeup. This allowance was also provided in ADM-021. When the RCO could not find any provision in 4-OP-038.1, for partial lifting of the

clearance on valve 4-114A, he attempted to use solely boric acid to fill the refueling cavity. The inspectors raised a concern related to procedure usage during this incident. The RCO could not find any procedural guidance for using normal blend. Therefore, instead of requesting further guidance from the Plant Supervisor-Nuclear (PS-N), he borated, using Administrative Procedure (AP) 0103.32, Reactor Cold Shutdown Conditions, revision dated September 22, 1988. This procedure provides guidelines for when in a cold shutdown condition. Section 8.8, specifies the boric acid flowpaths that can be taken credit for to satisfy TS 3.6.a, which states: When fuel is in the reactor there shall be at least one flow path to the core for boron injection. The preferred flow path was as follows: BASTs through BATPs to charging pump suction with discharge of charging pump to the reactor. The RCO utilized this flowpath to provide makeup to the refueling cavity. The inspectors reviewed this procedure and determined that the intent of Section 8.8 was not to provide steps for the operators to makeup to the refueling cavity. This section only listed the preferred and alternate boric acid flowpaths to the core. The inspectors determined that this procedure was inadequate for the evolution being attempted, and should not have been used.

AP 0109.1, Preparation, Revision, Approval, And Use Of Procedures, revision dated September 8, 1988, section 8.2.2, specifies if a procedure step cannot be completed as written or if in the judgement of the individual performing a procedure, completion of a specific step could result in an unsafe condition, conduct of the procedure shall be stopped, the system/components placed in a safe condition and the Plant Supervisor-Nuclear (PS-N) shall be notified. The required corrective actions shall be determined by the PS-N.

Contrary to the above, on October 15, 1988, the Unit 4 RCO did not consult the PS-N when he could not perform a makeup with normal blend due to primary water being isolated to the blender. Instead, the RCO attempted to makeup using solely boric acid using section 8.8 of AP 0103.32, Cold Shutdown Conditions, dated September 22, 1988. The intent of section 8.8 was not to provide steps for makeup and as a result the charging pump discharge line became momentarily clogged. If the acid had solidified in the discharge line, the TS required boric acid flowpath to the core would have been lost. This is the second example of violation 50-250,251/88-30-03.

On October 25, 1988, while attempting to add makeup water to the Unit 4 Component Cooling Water (CCW) surge tank, the CRDM/CCW cooler relief valves lifted and no increase in CCW surge tank level was noted. The surge tank is a single tank with a divider plate down the middle to provide independent suctions to the "A" and "B" headers of CCW. At the time of the event the "B" suction line from the surge tank was supposed to be plugged from inside the tank to facilitate work on the "B" CCW header downstream of the surge tank. Investigation revealed that the plug was actually installed in the "A" side suction. Thus, when attempting to fill the surge tank from the demineralized water supply, that portion of the

system was isolated from the tank due to the plug being installed on the wrong side of the tank. This in turn caused the CRDM/CCW relief to lift. The licensee determined that maintenance personnel used drawing 5610-T-E-4512, to identify which side of the surge tank the plug should be installed in. The drawing shows a sample valve (4-709) in the line just downstream of the surge tank, which indicated to maintenance personnel that the plug should be installed in the opposite header suction line. Further research showed that the drawing was in error in that, the sample valve (4-709) actually was located in the "B" header portion of the system. Therefore, whenever the sample valve was used as a point of reference to determine where to install the plug, the plug would always be installed on the wrong side of the tank. This discrepancy was previously identified on November 19, 1987, and documented in REA 87-260, dated December 7, 1987. This is the third example of IFI 250,251/88-30-05.

The inspectors expressed a concern to licensee management related to plant configuration control. The three events described above, along with previous drawing discrepancies identified in Inspection Reports 50-250,251/88-02 and 88-26, indicate a configuration problem exists. The inspectors noted that the Independent Management Appraisal (IMA) completed in early 1988, contained recommendations that specific action plans be developed and implemented to deal with the backlog of discrepant drawings. The licensee developed a corrective action plan which includes the following;

(1) Assignment of additional resources to eliminate the backlog of revisions to be incorporated into the drawings. The priorities of these will be based on their safety significance.

(2) Development and implementation of changes to the process used to update plant drawings. This will help ensure drawings are updated in a shorter time frame.

(3) Development and implementation of a single procedure that covers the entire as-built drawing update process to integrate the activities of the multiple organizations.

The changes to the process for updating drawings and the interdepartmental procedure for as-built drawing update were scheduled to be developed and implemented within one month after the Fall 1988, Unit 4 refueling outage. This outage was originally scheduled to end in December 1988. However, the end date could extend through March 1989, due to problems encountered with the Unit 3 generator rotor and the subsequent placement of the Unit 4 generator rotor into the Unit 3 generator. The inspectors encouraged the licensee to expedite the proposed corrective actions to help ensure that plant personnel have adequate drawings for the safe and reliable operation of the plant. The inspectors will followup on the licensee's corrective actions and the implementation of proposed changes during future inspections. This item will be tracked as an Inspector Followup Item (IFI) 250,251/88-30-05.

7. Exit Interview

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 October 28, 1988. 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:

- 50-250,251/88-30-01, Inspector Followup Item. Correct Diesel generator fuel oil pressure criteria to prevent entering TS action statement (paragraph 4).

- 50-250,251/88-30-02, Inspector Followup Item. Followup of corrective actions for leaking PORV diaphragm (paragraph 4).

- 50-250,251/88-30-03, Violation. TS 6.8.1, two examples; Failure to maintain an audible neutron flux monitor in the control room as required by Interim Technical Specification 3/4.9.2, (paragraph 5), and failure to use proper instructions for filling the refueling cavity (paragraph 6).

- 50-250,251/88-30-04, Inspector Followup Item. Corrective actions for maintaining effective SG blowdown effluent monitoring (paragraph 6).

- 50-250,251/88-30-05, Inspector Followup Item. Three examples requiring the licensee's corrective actions for inadequate drawings (paragraph 6).

- 50-250,251/88-30-06, Inspector Followup Item. Long term corrective action to prevent diesel generator overload from ICW pump auto start during accident conditions (paragraph 6).

- Licensee Identified Violation (LIV). Failure to notify the NRC within the required time that both EDGs were out of service (paragraph 4).