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

Report Nos.: 50-250/88-39 and 50-251/88-39

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: November 24 - December 22, 1988

Inspectors: William K. Poertner for — 1/19/89
R. C. Butcher, Senior Resdient Inspector — Date Signed

William K. Poertner for — 1/19/89
T. F. McElhinney, Resident Inspector — Date Signed

William K. Poertner for — 1/19/89
G. A. Schnebli, Resident Inspector — Date Signed

Approved by: Bruce A. Wilson for — 1/23/89
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, operational safety and plant events.

Results: One violation with two examples was identified. Weaknesses in the licensee's clearance program and failure to maintain reactor coolant system pressure/temperature within operational limits. Licensee management was made aware of the Residents' concern regarding the identified problems which indicated weakness in the clearance program.

A severity level V violation with no written Notice of Violation was identified. Failure to follow procedures resulting in de-energization of the wrong inverter causing control room and containment ventilation isolation.

One Licensee Identified Violation was identified. Accumulator levels could be outside TS operating band due to installation and calibration errors.

Three Inspector Followup Items were identified. Resolution of the root cause of cracked flanges found in the ICW piping; resolution of the root cause of an unlanded spade connection in the EDG control panel; and verification that the reactor cavity seal is adequately tested.

Also, due to NRC and industry concerns regarding operation with known dc grounds, the Residents requested, and Licensee Management committed to clearing all dc grounds prior to Unit 4 startup from the present refueling outage.

REPORT DETAILS

1. Persons Contacted

Licensee Employees
J. W Anderson, Quality Assurance Supervisor
J. Arias, Regulation and Compliance Supervisor
*L. W. Bladow, Quality Assurance Superintendent
*W. F. Conway, Sr. Vice President
J. E. Cross, Plant Manager-Nuclear
*J. M. Donis, Operations Support Supervisor
*R. J. Earl, Quality Control Supervisor
T. A. Finn, Training Supervisor
S. Hale, Engineering Project Supervisor
*R. D. Hart, Regulation and Compliance Engineer
*J. W. Kappes, Maintenance Superintendent
V. A. Kaminskas, Reactor Engineering Supervisor
J. A. Labarraque, Senior Technical Advisor
*E. Lyons, Compliance Engineer
*F. Mahler, Controls Supervisor-Services Department
*R. G. Mende, Operations Supervisor
*J. S. Odom, Site Vice President
*L. W. Pearce, Operations Superintendent
F. H. Southworth, Technical Department Supervisor
*R. J. Stevens, Manager Plant Licensing
J. C. Strong, Mechanical Department Supervisor
D. Tomaszewski, Instrument and Control Department Supervisor
M. B. Wayland, Electrical Department Supervisor
J. D. Webb, Operations - Maintenance Coordinator
W. R. Williams, Assistant Superintendent Planned Maintenance

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

*Attended exit interview on December 22, 1988.

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 250,251/88-07-01. This violation included three examples of failure to follow procedures. The first example involved a vent valve on the AFW Nitrogen Backup System found lockwired open when it was required to be lockwired closed. The second example involved three

instances where a pressure indicator isolation valve was found open, contrary to an existing clearance tag. The third example involved an Intake Cooling Water (ICW) heat exchanger isolation valve not being fully open after a clearance release was performed. The inspectors reviewed the corrective actions for each of the examples and found them to be appropriate. However, as discussed in paragraph 7 of this report, a problem still exists with proper control of clearance orders. Although this item will be closed, the continuing problems associated with clearances will be tracked by violation 250,251/88-39-01. Violation 250,251/88-07-01 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) IEB 84-03. Refueling Cavity Water Seal. This item was previously closed in Inspection Report 85-11, however, the licensee's procedures for leak testing the inflatable reactor cavity seal were not adequate for testing after the initial installation test. A new seal design was installed in Unit 4 during this refueling outage per PC/M 87-100. Testing of the inflatable seal was properly accomplished per section 13.0 of the PC/M. This section requires testing the seal both deflated and inflated with the cavity full, however, this would only be accomplished during the initial installation testing required by the PC/M. Subsequent testing of the seal would be accomplished per 3/4-OP-201, Filling/Draining the Refueling Cavity and the SFP Transfer Canal. However, this procedure did not contain any testing requirements of the seals after the cavity was full. The licensee modified the procedure, 3/4-OP-201, on December 20, 1988, to require a leak test of the cavity seal with the cavity filled between two and five feet above the seal and the inflatable seal depressurized to ensure the primary compression seals are holding. The inspectors considered this test to be inadequate in that the seal is not tested with the cavity filled to the normal operating level of 56 feet 10 inches to 57 feet 2 inches. Further discussions with appropriate licensee management indicated that testing at the lower levels specified were more conservative because increasing the level would cause the seals to seat tighter due to the increased pressure from the head of water. However, the licensee agreed to add an additional leak inspection when the cavity was full and also to ensure the inflatable seal was depressurized until completion of the final leak test. This is identified as Inspector Followup Item 250,251/88-39-04, ensure the cavity seal is adequately tested.

4. Onsite Followup and In-Office Review of Written Reports of Nonroutine Events (92700/90712)

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.

(Closed) LER 250/88-04, Auxiliary Feedwater Initiation on Low Steam Generator Level Due to Inadequate Monitoring of Steam Generator Level. This event is similar to the actuation of the Overpressure Mitigation System (OMS) event described in paragraph 9 of this report. These two events involved similar circumstances. Therefore, LER 250/88-04 is closed, however, the inspectors will track future corrective actions via violation 250,251/88-39-01.

(Closed) LER 250/88-06, Missed Surveillance of the in-service Gas Decay Tank Hydrogen and Oxygen Concentration. The licensee implemented the proposed corrective actions which included:

> Adding the surveillance of the in-service Gas Decay Tank to the Primary Chemistry daily worksheets which are signed by the accountable supervisor.
>
> The supervisor and technician involved were counseled.

The inspectors found the corrective actions to be complete. LER 250/88-06 is closed.

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:

> 3/4-OSP-201.1 Reactor Control Operator Daily Logs
> 4-OSP-019.1 Intake Cooling Water Pump Inservice Test

No violations or deviations were identified within the areas inspected.

6. Monthly Maintenance Observations (62703)

Station maintenance activities on 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 Unit 4 CCW Heat Exchangers.
- Installation of Unit 4 MSIV Air Accumulators.
- Repair of ICW Pump 3B discharge Flange.
- Repair of MOV-3-832, Primary Water Makeup to CCW Surge Tank.

During the current Unit 3 and Unit 4 outages, the inspectors have noted several instances of problems with clearances. Some of these issues were discussed in Inspection Report 88-36, and several more have been identified during this inspection period, such that the inspectors consider more licensee management attention is needed. The problems identified include the following:

- On October 15, 1988, MSIV 4B was found partially open during the Unit 4 containment integrity walkdowns. The valve was tagged closed under a clearance.
- On November 18, 1988, valve 4-50-324, 4A ICW/CCW Basket Strainer Inlet Valve, was found closed. The valve was tagged open under clearance 4-88-11-022R.
- On November 21, 1988, condensate was spilled into the turbine building area, on two occassions, through disassembled valves 4-20-121 and 4-20-221, 3-way valves for 4A and 4B feedwater pump discharge line. These valves direct water to, or bypass water around 6A and 6B feedwater heaters. The clearances listed on

the PWOs to work the two valves were inadequate to provide proper isolation for the work being performed.

- On November 22, 1988, a licensee QA inspector, performing a review of the major boundary valves being used to isolate valves 4-20-121 and 4-20-221, found another deficiency. The discharge valve for the 4A feedwater pump, MOV-4-1420, was found to be fully open with two separate clearance tags on the manual operator of the valve that required the valve to be in the shut position.

- On December 1, 1988, intake cooling water was inadvertently valved into the 3A ICW/TPCW basket strainer. This resulted in running salt water down toward the south gate and into the electrical manway by the spare main transformer. This manway had an electrical short in the wiring that resulted in a fire.

- On December 2, 1988, during the performance of safeguards testing on Unit 3, the "A" Steam Generator feed bypass valve, FCV-3-479, failed to close when required on an isolation signal. Subsequent licensee investigation found the fuses in the circuit that provided the close signal to the valve pulled out and in a polybag with clearance 3-87-10-101. The clearance was issued and the fuses pulled on November 3, 1987, and had been in that condition since that date. Review of the Clearance Book indicated that the clearance did not exist in the book or the index. In addition, the removal of the tag and re-installation of the fuses required independent verification per AP 0103.4, In-Plant Equipment Clearance Orders. This item is still under review by the licensee and the resident staff and will be addressed further in a future report.

- One other issue concerning the method of controlling the release of clearances was discussed with responsible licensee management during this period. On November 17, 1988, the operations department attempted to open MOV-4-750, RHR pump suction valve, electrically to place the valve on its backseat for repacking. The valve failed to open and subsequent investigation by the licensee indicated the following:

  The valve was removed from service on October 30, 1988, under clearance 4-88-10-162, to perform an EQ inspection of the MOV. The EQ inspection was completed on November 1, 1988. Additional work on the MOV per P/CM 86-169, was commenced on November 14, 1988, under the same clearance used to perform the EQ inspection, however, the PWO to perform the work was not added to the clearance. On November 17, 1988, when the operations department was requested to backseat the valve for repacking, they obtained permission to perform a partial lift on the clearance to re-energize the MOV to operate it. The

electrical supervisor who authorized the partial lift was only aware of the EQ work on the valve and knew that it was complete. He was not aware the work per the P/CM had started and was not complete at that time. Therefore, when operations attempted to open the MOV it would not operate. The inspectors are very concerned in this area, not only from a plant safety standpoint but also a personnel safety standpoint. The NRC considers the licensee's clearance program should require that all PWOs be listed on their respective clearance. This would ensure the system would be the backstop rather than relying on a persons memory to recall all work being performed under a specific clearance.

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 Section 5.1 of ANSI N18.7-1972. ANSI N18.7-1972, Section 5.1.2 specifies that procedures shall be followed. Administrative Procedure 0103.4, In-Plant Equipment Clearance Orders, revision dated August 26, 1988, specifies the required instructions to obtain, issue and release clearances to ensure safety and protection of plant personnel and equipment.

Contrary to the above, the numerous examples discussed above identify a weakness in the licensee's program to provide adequate control over clearances to ensure personnel and equipment protection. This will be identified as violation 50-250,251/88-39-01.

7. 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

On November 1, 1988, a conference call was held between FPL, NRC Region II and NRR personnel concerning a Technical Specification (TS) interpretation. TS 4.1, Table 4.1-2, Item 10, requires that the cold leg accumulators be sampled and verified to be 1950 ppm or greater, prior to Reactor Coolant System (RCS) heatup above 200 degrees F. However, TS 3.15.1, Overpressure Mitigating System (OMS), requires that, with RCS pressure boundary intact, the valve (MOV-869) required to be opened to fill the cold leg accumulators be closed with power removed until RCS temperature is greater than 380 degrees F. A violation had been issued (250,251/87-35-01) previously due to the licensee heating up greater than 200 degrees F without sampling a cold leg accumulator. Corrective action to the violation included submitting a license amendment. This amendment was submitted on February 3, 1988, and entitled "Safety Injection Accumulators". During the November 1, 1988, conference call, the NRC outlined the reasons why the amendment would not be reviewed. The reasons were; this licensing action received a low priority ranking; limited NRC resources were available to review such licensing actions; and since the proposed TS changes in the February 1988 submittal are already included in the TS Revision Project license amendment, this would be sufficient to resolve this issue. The NRC also interpreted the current TS to not require the cold leg accumulators to be sampled when they are empty. This interpretation was formally submitted to the licensee, from the NRC, in a letter dated December 8, 1988.

Generic Letter 88-17, Loss of Decay Heat Removal, was issued on October 17, 1988. The Generic Letter requires certain actions by the licensee with responses. Due to the sensitivity of this issue and the potential consequences while operating in a reduced inventory condition, NRC Headquarters requested the Regions alert the resident inspectors at sites that are in, or will soon be in, a reduced inventory condition. The residents have discussed this issue with licensee management and one event where the licensee committed to more conservative operation than that required by Technical Specifications, due to the concerns noted in Generic Letter 88-17, was documented in Inspection Report 50-250,251/88-30.

No violations or deviations were identified in the areas inspected.

8. Plant Events (93702)

The following plant events were reviewed to determine facility status and the need for further followup action. Plant parameters were evaluated during transient response. The significance of the event was evaluated

along with the performance of the appropriate safety systems and the actions taken by the licensee. The inspectors verified that required notifications were made to the NRC. Evaluations were performed relative to the need for additional NRC response to the event. Additionally, the following issues were examined, as appropriate: details regarding the cause of the event; event chronology; safety system performance; licensee compliance with approved procedures; radiological consequences, if any; and proposed corrective actions.

On October 21, 1988, during maintenance and calibration of Unit 3 cold leg accumulator level indication loops, I&C personnel determined that accumulator levels previously monitored could have been in error due to installation and calibration errors. The accumulators for both units were declared out of service until this issue was resolved. Unit 3 was in Mode 5 and Unit 4 was defueled at this time, therefore, the accumulators were not required to be in service. An engineering evaluation was performed based on data obtained from the Unit 3 cold leg accumulator level transmitters. The following items represent the potential errors in the previous calibration calculations; calibration range and span errors; installation errors; and static pressure correction errors. The errors were evaluated for both minimum and maximum Technical Specification (TS) values and were calculated based on the respective worst case transmitter elevation. The calculations done for the Unit 3 cold leg accumulators showed the following:

a. The worst case total error was on level transmitter (LT) 3-926, regarding maximum TS volume. An error of 0.41 inches level resulted in 18.5 gallons more than the TS allowable volume of 6664 gallons.

b. The worst case total error was on LT-3-920 and 924, regarding minimum TS volume. An error of 0.30 inches level resulted in 13.5 gallons less than the TS allowable volume of 6544 gallons.

Based on this information, it was possible for a high or low accumulator level alarm to be received, and the actual level could have been outside the TS operating band. As a result of these conclusions, the licensee evaluated the nuclear safety concerns. The licensee issued a Safety Evaluation Report on December 9, 1988, which demonstrated that the basis for the LOCA related analysis used to license Unit 3 would have remained valid with operation outside the TS band on accumulator water volume. The licensee has completed corrective actions for Unit 3 which included installing new level transmitters with improved subloop accuracy. The Unit 4 transmitters will be replaced prior to returning the unit to service.

The failure to maintain the cold leg accumulator water volume between 875-891 cubic feet (6544-6664 gallons) is a violation of TS 3.4.1.a.3. However, this violation meets all of the criteria delineated in 10 CFR, Part 2, Appendix C, regarding licensee identified violations. Therefore, a notice of violation will not be issued. The corrective actions will be

tracked by the Licensee Event Report (LER) which is due to the NRC 30 days after discovery of event.

On November 30, 1988, at approximately 1215, the plant fire team responded to a reported fire in the Unit 3, 480 volt load center room. The fire had been reported by a fire watch, making his routine rounds, noting an electrical fire smell and upon further investigation finding smoke in the room. The fire team found heavy smoke throughout the room and the 3B load center was determined to be the source. The load center was de-energized from the 4160 volt feed and the cubicle was inspected. The team found a journeyman electrician tool pouch and glove bags inside the cubicle leaning against a space heater in the cubicle. Licensee investigation into this issue determined that two electricians that were assigned to work in this area had caused the fire. Upon breaking for lunch they decided to store their tools and equipment in the rear of the load center cubicle to prevent theft. In doing so, the tool bags came in contact with the space heater and subsequently caught fire. The cubicle was thoroughly inspected and cleaned up and returned to operation at 2:30 p.m. No damage to equipment due to fire or smoke was noted. Licensee supervision discussed the situation with the two electricians responsible and the following day the electricians discussed the event with the other shop personnel. The shop was instructed that common routine practices can sometimes place individuals in a secure frame of mind, which causes a lack of attention to detail, leading to mistakes.

On December 2, 1988, the licensee reported a significant event in accordance with 10 CFR 50.72 (b)(2)(ii). The Unit 4 Reactor Control Operator (RCO) had transferred load from the 4B 120 Volt Vital Instrument AC Inverter to the B Spare Inverter, in order to perform preventive maintenance on the 4B Inverter. This evolution was being done in accordance with Operating Procedure (OP)-003.3, 120 Volt Vital Instrument AC System. After the load was transferred the RCO attempted to de-energize the 4B Inverter per section 6.1 of OP-003.3, by placing the inverter output breakers to OFF. However, the RCO inadvertently switched the B Spare Inverter output breaker to OFF. This led to the loss of vital AC bus 4P08, which supplies power to the process radiation monitoring racks. The de-energization of the containment air particulate and gas radiation monitors initiated a Control Room and Containment Ventilation isolation. The operator promptly restored power to 4P08 by closing the BS Inverter output breaker. The control room and containment ventilation systems were subsequently returned to normal alignment. The licensee attributed the cause of this event to personnel error and counseled the operator on procedure usage. The licensee is also considering a procedure enhancement to OP-003.3 to have the operator verify the inverter is unloaded before opening the output breaker.

The failure to follow procedure 0-OP-003.3, in that the wrong inverter was de-energized is another example of violation 250,251/88-39-01. However, this example will not be cited in the Notice of Violation. The inspectors determined that the enforcement policy in 10 CFR, Part 2, Appendix C, paragraph V.A., concerning Severity Level V violations, could be applied

in this situation. Therefore, the licensee is not required to issue a formal response. The inspectors will track the corrective actions to the event via the Licensee Event Report (LER) which is due 30 days from the date of occurrence.

On December 2, 1988, the Unit 3 Reactor Control Operator (RCO) began making up to the Component Cooling Water (CCW) surge tank. This was done by opening valve 3-862, which supplies primary water to the surge tank. The RCO noticed that the open indication was not received in the control room. When the RCO attempted to close the valve after making up, the valve would not close. The RCO instructed a Nuclear Operator (NO) to isolate 3-832 by manually closing 3-711B. While the N.O. was manually closing this valve the surge tank continued to fill until water overflowed from an open manway. This manway was open due to work being done on the CCW surge line. The licensee estimated 10-50 gallons of water flowed on to the spent fuel pit floor and into the spent fuel pit. The CCW surge tank was drained to the normal level (50 percent) and the water in the spent fuel pit area was cleaned up. Chemistry also sampled the SFP for molybdates and determined they were below the minimum detectable amount. A plant work order was issued to repair valve 3-832.

On December 9, 1988, the Unit 3 Overpressure Mitigating System (OMS) actuated due to Reactor Coolant System (RCS) pressure exceeding the setpoint of 415 psig. The RCO had energized the backup group A pressurizer heaters to raise primary pressure in an attempt to reduce 3A charging pump noise. During this evolution the RCO was also stroke testing Motor Operated Valve (MOV) 3-536, the pressurizer power operated relief valve (PORV) block valve. While the RCO was involved in testing MOV-3-536, the RCS pressure increased until the OMS setpoint was reached. PORV 455C opened to relieve the pressure. The RCO then secured the pressurizer heaters and primary pressure was reduced to approximately 370 psig. The inspectors determined that the root cause of this event was personnel error, in that the Unit 3 RCO did not monitor the appropriate parameters during the evolution. Operating Procedure (OP)-041.2, Pressurizer Operation, dated December 2, 1988, section 5.1.2, specifies that the pressurizer heaters and/or sprays be used to maintain RCS pressure between 330 and 380 psig.

Contrary to the above, the Unit 3 RCO failed to maintain RCS pressure below 380 psig, as a result, the OMS actuated due to RCS pressure reaching the setpoint of 400 to 430 psig. This is another example of violation 250,251/88-39-01.

During an overhaul on a 4B ICW discharge check valve the licensee noted that the piping flange downstream of the 90 degree elbow was cracked. Inspection of the same flange on the 3B ICW header revealed a crack also. The crack location on both flanges was in the same location (i.e. at the center of a bolt hole, having propagated through the full length of the flange, including the hub). The flanges are one piece and screw onto the ICW piping. The licensee concluded that the crack had developed since the last ICW pump changeout. Due to the large crack size once the joint was

disassembled, this condition should have been detected during the last ICW pump change-outs. The ICW pump change-outs were conducted on the following dates:

PUMP	LAST WORK RECORD FOR FLANGE DISASSEMBLY	ELAPSED TIME
3B ICW	5-4-87	20 months
4B ICW	12-18-87	12 months

An Event Review Team (ERT 88-018) was formed to do a root cause investigation. Teledyne has been contracted to analyze the broken flange to determine the root cause of the flange failures. The ERT identified several possible root causes that could have contributed to the failures. The ERT recommended a surveillance program to monitor pump discharge flanges periodically for evidence of cracking. The ERT also stated that the identified root causes pertained to the construction, maintenance and design of the system and was not a deficiency with respect to the specification of the existing part; therefore, an identical replacement could be installed and the affected portion of the system returned to service with no restriction on plant startup. The surveillance would be an interim measure until the root cause analysis is completed and final recommendations can be made. The affected flanges were the original flanges and have been in place for many years. The final resolution of the cracked flanges will be identified as Inspector Followup Item (IFI) 50-250,251/88-39-03 .

On December 10, 1988, the licensee reported a Significant Event in accordance with 10CFR 50.72(b)(2)(iii)(A). Personnel working inside the B Emergency Diesel Generator (EDG) engine control panel discovered a spade style connector unlanded. The unlanded lead was found to be the input to the ES 200 RPM relay and the ZS 40 RPM relays. These relays receive a speed proportional signal from the frequency generator. Although this lead was not landed, it was in contact with an adjacent terminal which resulted in the electrical connection being made up. If the input from the frequency generator was lost, three functions would be affected. The EDG Room Vent Fan, would not have functioned, therefore, the fan wouldn't have started. The Start Failure logic would initiate after a 15 second time delay which would trip the engine. Also, the EDG A breaker lockout would occur after the 15 second time delay. The licensee initiated a plant work order to re-land the spade connection to the terminal and the B EDG was declared out of service. The A EDG was available for service but was considered out of service awaiting dispositioning of a design equivalent engineering package to replace engine panel clips with seismic clips. The spade connection was subsequently landed and the B EDG was tested satisfactorily prior to returning it to service. The cause of the connection not being properly landed was unknown at the end of the inspection period. The inspectors will track this investigation as Inspector Followup Item 250,251/88-39-02.

On December 15, 1988, a Nonconformance Report (NCR 88-0241) was initiated by the licensee documenting a possible 10 CFR, part 21, concern with the reactor trip breakers. The licensee uses DB-50 trip breakers manufactured by Westinghouse. The licensee had identified that welds on the DB-50 reactor trip breaker secondary contact brackets had failed. The welds are spot welds utilized to assemble the four bracket parts and failure of these welds could cause discontinuity of the signals passing through the secondary contacts. This would lead to de-energization of the Undervoltage Trip Attachment (UVTA) which would result in the breaker tripping open. Based on Westinghouse recommendations and because Unit 3 was preparing to heat up for start up from a maintenance outage, the licensee installed non-suspect brackets on the Unit 3 reactor trip breakers. The present location and disposition of DB-50 breakers are as follows:

Unit 3

Location	Serial Number
3A Trip	850.181-1 stamp 11 (Bracket replaced)
3B Trip	850.181-3 stamp 13 (Bracket replaced)
3A Bypass	850.013-1 stamp 10 (Bracket replaced)
3B Bypass	850.013-3 stamp 09 (Bracket replaced)

Unit 4

Location	Serial Number
4A Trip	24Y5724B-3 (Bracket removed, used on stamp 9/850.013.2)
4B Trip	24Y5724B-4 (Bracket removed, used on stamp 13/850.181-3)
4A Bypass	24Y5723B-8 (Bracket removed, used on stamp 10/850.013-1)
4B Bypass	24Y5724B-2

Stores (Breakers renumbered after refurbishment by Westinghouse)

880.510-1 (was 24Y5723B)
880.510-2 (was 24Y5723B)
880.510-3 (was 850.181-2, stamp 12) Suspect Bracket

Electrical Shop
24Y5724B stamp 1 (Bracket removed, used on 850.181-1)
24Y5723B stamp 5

Based on the above changes, the licensee started heatup on Unit 3. Unit 4 is defueled at present. The licensee received correspondence from Westinghouse indicating that a total of five reactor trip breakers with suspect brackets were shipped to Turkey Point. These reactor trip breakers have been identified and were either modified or are on hold. Westinghouse has notified NRC headquarters of their findings.

9. Resolution of Unit 3 Drawing Discrepancies

Due to NRC concerns regarding inaccurate drawings as documented in the cover letter to Inspection Report 50-250/88-30 and 50-251/88-30, the licensee initiated a program to identify significant outstanding drawing discrepancies for updating prior to Unit 3 startup.

The inspectors reviewed the licensee program for the identification and resolution of drawing discrepancies. Various aspects were assessed for completeness and adequacy in the fulfillment of all required corrective actions.

The screening process used by the licensee to identify significant drawings which needed to be reviewed, assigned all drawings to five priorities:

a. Safety Related Sensitive Systems
b. Safety Related Non-Sensitive Systems
c. Non-Safety Related Sensitive Systems
d. Non-safety Related Non-Sensitive Systems
e. Remainder

The licensee determined the drawings which were contained in each priority. All drawings which were contained in priorities 1 through 4 were assessed per the drawing correction program. The inspector reviewed the plant Technical Specifications, FSAR, and Appendix R Safe Shutdown Analysis, and determined the systems required to fulfill the requirements of each. All of the required systems are contained in priorities 1 through 4 of the licensee screening process.

The initial screen of NCRs and REAs performed by the licensee screened titles only. During this screen, 466 NCRs were removed from consideration as being unrelated to drawings. The inspectors reviewed the listing of all open NCRs and REAs and reviewed approximately 25 percent of the NCRs removed from the process during the initial screen.

The second screen removed discrepancy types which were not drawing discrepancies, such as enhancements, completed items, or vendor manual updates. This reduced the number of items under review by 195 NCRs and 74 REAs. The inspectors reviewed approximately ten percent of the items which were removed from the review process and found no problems with the screening process at this point.

The final screen removed discrepancies which dealt with Unit 4 only and with items which were not priority one through four. This reduced the numbers by an additional 84 NCRs and 130 REAs. The inspectors reviewed approximately ten percent of the removed items and found no problems with the screening process.

The remainder of the items under consideration, 44 NCRs and 80 REAs, received a 100 percent review by the inspectors to determine the

significance of the discrepancies identified by the licensee. The majority of the discrepancies were incorrectly identified valves on the drawing (e.g. identified as a gate valve instead of as a globe valve) and items not shown on drawings (e.g. root isolation valves on instrumentation). The inspectors reviewed the operability evaluations that were performed for the NCRs. All of the evaluations concluded that there were no major operability concerns. The inspector's review of the evaluations determined that the evaluations were accurate. A review of the REA program ascertained that no requirements exist for performing an operability evaluation for an REA. The licensee discontinued using REAs to identify discrepant drawings, as a result of the inspectors' concerns. The licensee reviewed the backlog of open REAs and determined that approximately 20 needed to have an operability evaluation performed. The inspectors examined the preliminary evaluations for these REAs and found no problems.

Two concerns with the operability evaluation process were noted by the inspectors;

When the engineer performing the REA operability evaluation identifies a mode restriction is needed until correction is completed on the item, there is no formal mechanism to assure that this information is transmitted to the plant operations staff in a timely manner. The licensee concurred with this determination and stated that the item would be reviewed to ascertain what, if any, corrective actions will be taken to resolve it.

The initial review performed on an NCR does not include either a 10 CFR 50.59 evaluation or a screen to determine if a 10 CFR 50.59 evaluation is needed. The screen/evaluation is not performed until the disposition for the item is implemented. At times, this may be as long as two years after the identification of the discrepant condition. The screening process needs to be performed at the time the condition is identified, not when the resolution is being implemented. This will prevent an instance where an unevaluated condition exists for a period of time during which the licensee should have been familiar with it. The licensee stated that the need for the screening/evaluation will be assessed and corrective actions, if warranted, will be developed.

The inspectors reviewed the process used to update the plant operating procedures to reflect the changes to the plant drawings. The procedure upgrade program personnel review the drawing changes against all applicable procedures and drafts a revision. Other personnel from the group walkdown the system with the revised procedure to assure that the proposed changes are indeed correct and that the revision will accurately reflect actual plant conditions. The procedure upgrade group has identified approximately 75 procedures to be revised, mostly single line revisions. Revision approval is targeted for three days following red-line drawing issuance.

The licensee identified two areas that would require operator training in relation to the changes of the plant operating drawings. These areas concerned enhancements to the logic diagrams for the sequencer and 4160 Volt bus protection circuits. The inspectors reviewed the drawing changes and concurred that these were the only areas that required operator training. This training was scheduled to be performed on shift prior to resuming power operations.

The inspectors reviewed 100 percent of the preliminary red-lined drawings and the associated NCRs and REAs produced as a result of this effort. Except for several minor drafting errors, which have been corrected by the licensee, no problems were found with the drawings. The drawings are not obscured by the red-line revisions, which were usually a small number on each drawing (approximately 700 discrepancies on 55 drawings).

The actions taken by the licensee to correct the existing problems with the operating drawings appear to have been adequate for the Unit 3 startup. No further action is warranted, at this time, on the drawing discrepancy issue on Unit 3.

No violations or deviations were identified in the areas inspected.

10. 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 December 22, 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:

50-250,251/88-39-01, Violation with two examples. Weaknesses in licensee's clearance program and failure to maintain reactor coolant system pressure/temperature within operational limits, (paragraphs 6 and 8).

50-250,251/88-39-02, Inspector Followup Item. Resolution of root cause for unlanded spade connection in the EDG control panel, (paragraph 8).

50-250,251/88-39-03, Inspector Followup Item. Resolution of the root cause for cracked flanges found in the ICW piping, (paragraph 8).

50-250,251/88-39-04, Inspector Followup Item. Ensure the reactor cavity seal is adequately tested, (paragraph 3).

Severity Level V Violation with no written Notice of Violation. Failure to follow procedures resulting in de-energization of the wrong inverter and Control Room and Containment ventilation isolation, (paragraph 8).

Licensee Identified Violation. Accumulator levels could be outside TS operating band due to installation and calibration errors, (paragraph 8).