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

Report Nos.: 50-250/88-02 and 50-251/88-02

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: January 18 - February 25, 1988

Inspectors: _____ for 4/13/88
D. R. Brewer, Senior Resident Inspector Date Signed

_____ for 4/13/88
T. F. McElhinney, Resident Inspector Date Signed

_____ for 4/13/88
G. A. Schnebli, Resident Inspector Date Signed

Approved by: _____ for 4/13/88
Richard V. Crlenjak, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, unannounced inspection entailed direct inspection at the site, including backshift inspection, in the areas of annual and monthly surveillance, maintenance observations and reviews, engineered safety features, operational safety, facility modifications and plant events.

Results: One violation with three examples for failure to meet the requirements of Technical Specification (TS) 6.8.1 was identified. (250, 251/88-02-01).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*J. S. Odom, Vice President
*C. J. Baker, Plant Manager-Nuclear
*L. W. Pearce, Operations Superintendent
*F. H. Southworth, Senior Technical Advisor
J. W. Kappes, Maintenance Superintendent
L. L. Thomas, Outage Manager
J. P. Mendieta, Services Manager-Nuclear
R. A. Longtemps, Mechanical Maintenance Department Supervisor
T. A. Finn, Training Supervisor
J. D. Webb, Operations - Maintenance Coordinator
W. R. Williams, Assistant Superintendent Planned Maintenance
D. Tomaszewski, Instrument and Control (I&C) Department Supervisor
*J. C. Strong, Maintenance Supervisor (Acting)
L. W. Bladow, Quality Assurance (QA) Superintendent
*R. J. Earl, Quality Control (QC) Supervisor
*J. A. Labarraque, Technical Department Supervisor
B. A. Abrishami, Acting Technical Department Supervisor
*R. G. Mende, Operations Supervisor
*J. Arias, Regulation and Compliance Supervisor
V. A. Kaminskas, Reactor Engineering Supervisor
*R. D. Hart, Regulation and Compliance Engineer
G. Solomon, Regulation and Compliance Engineer
*T. V. Abbatiello, Supervisor Engineering Performance Monitoring Section QA
*R. Carey, Communications Representative

Other NRC inspectors on-site during report period:

P. J. Kellogg

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

*Attended exit interview

2. 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 January 29, 1988. The areas requiring management attention were reviewed. No proprietary information was provided to the inspectors during the reporting period.

One violation was identified: Failure to meet the requirements of TS 6.8.1, three examples (paragraph 9); in that a valve required to be open in accordance with the Caution Tag Clearance Procedure was found closed; flow indicators were removed from the intake cooling water ICW system

without administrative authorization; and a surveillance procedure was inadequate due to non-conservative acceptance criteria.

3. 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.

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

(Closed) IFI 250, 251/85-04-01. Develop and implement a shelf-life program and incorporate shelf-life requirements for Grinnel valve diaphragms. The licensee has developed a shelf-life program which is controlled through Administrative Procedure O-ADM-900, entitled Control for Limited Shelf Life Material, current revision dated September 22, 1987. The program is further controlled through Quality Instruction 4.1, Appendix C, entitled Guide for Shelf-Life Evaluation and Control. Plant records were reviewed and numerous types of Grinnel diaphragms were included in the shelf-life program. One example is a Grinnel-Saunders replacement diaphragm used in reactor coolant filter inlet and outlet isolation valves for Units 3 and 4. The diaphragm (stock number 575-88205-2) has a 4 year shelf-life. This item is closed.

(Closed) IFI 250,251/87-35-05. Develop a mechanism to ensure that superseded drawing revisions are not issued to plant personnel. The licensee has always required that each requested drawing be visually verified to be current prior to being issued. The event discussed in Inspection Report 250, 251/87-35, documented a single occasion during which the verification was inadvertently omitted. As a corrective action, the drawing request form has been modified to require written certification that the verification has been performed. A document control technician initials and dates the request form. The required signoff is beneficial because it provides a reminder to verify the correct revision. This action will prevent a recurrence of this concern. This item is closed.

(Closed) IFI 250, 251/85-26-07. Determine whether Off Normal Operating Procedure (ONOP) 15608.1 requires improved instructions on mitigating the consequences of a loss of instrument air. The licensee has performed an evaluation of the procedure and has issued procedure O-ONOP-13, Loss of Instrument Air, current revision dated November 3, 1987, which supersedes ONOP 15608.1. While a complete list of components affected by the loss of instrument air has not been developed, the failure modes of air dependent systems has been identified. Both the Auxiliary Feedwater (AFW) and Main Steam Isolation Valve (MSIV) systems utilize instrument air during routine operation. The licensee has upgraded the nitrogen backup supplies to these systems, with the exception of the Unit 4 MSIV system which will be

completed during the refueling outage scheduled for September 1988. A review has been completed of procedure O-ONOP-13 and it adequately describes the actions to be taken upon loss of instrument air and specifically addresses the operation of the MSIV and AFW systems using their nitrogen backup supplies. This item is closed.

(Closed) CAL 250, 251/87-01. On October 6, 1987, Region II issued Confirmation of Action Letter (CAL) 87-01. The letter confirmed a licensee commitment that a specified Reactor Operator would not resume his licensed duties until agreed upon by the Regional Administrator, Region II, NRC.

This issue was closed in licensee letter L-88-12, dated January 11, 1988. The licensee stated that the Reactor Operator voluntarily terminated his employment with FPL effective October 21, 1987. A letter requesting the termination of his license was submitted to the NRC on November 20, 1987, (L-87-485). All conditions of the CAL were met. CAL 250, 251/87-01 is closed.

(Closed) GL-81-21. Natural Circulation Cooldown (25586). During this inspection period, the licensee's actions to implement Generic Letter 81-21, Natural Circulation Cooldown were reviewed by a Region-based inspector.

The inspector determined from the review of training records, that the training includes both classroom and simulator training on natural circulation cooldown. The above training is included in RO and SRO certification training and in the operator retraining programs. Emergency Operating procedures were reviewed to ensure they followed the Westinghouse Owners Group (WOG) guidelines with respect to step content, specific plant parameters had been added, cooldown rates, subcooling temperature limitations, hold point for reducing head temperatures, and step deviations are documented.

One minor discrepancy identified during the inspection has been corrected by the Licensee.

Additionally, the inspector noted during the review that specific plant information could be improved by the addition of more information. Examples of this are:

a. RCPs should be run in order of priority to provide normal pressurizer sprays. This step could include the actual priority of pumps i.e. B then C.

b. Verify Cold Shutdown Boron Concentration by sampling, instructs the operator to call Chemistry Department to take a boron sample. Specific sample points should be included. This is an inspector followup item and will be looked at during a subsequent inspection of the Emergency Operating Procedures (IFI 50-250/251-88-02).

5. Onsite Followup and In-Office Review of Nonroutine Events (92700/92712)

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 250/87-01. Automatic Auxiliary Feedwater Pump Actuation Following Attempt to Start Steam Generator Feedwater Pump (SGFP). The licensee conducted a thorough investigation to identify the root cause of this problem. Each component in the circuitry between the control switch and the SGFP breaker, including the breaker, was verified to be functioning properly. The SGFP was successfully started and this problem has not recurred. LER 250/87-01 is closed.

(Closed) LER 250/88-01. Turbine Runback Due to Dropped Control Rod and Subsequent Manual Subcritical Reactor Trip When the Additional Control Rods Dropped Into the Core. As a result of this occurrence, violation 250, 251/87-54-02 was issued. Followup and closure of this item will be tracked through evaluation of the licensee's response to the violation. LER 250/88-01 is closed.

6. Monthly and Annual Surveillance Observation (61726/61700)

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:

4-OSP-203	Engineered Safeguards Integrated Test
3/4-OSP-041.1	Reactor Coolant System Leak Rate Calculation
3-PMI-28.3	RPI Hot Calibration, CRDM Stepping Test and Rod Drop Test
3-OSP-059.1	Source Range Nuclear Instrument Analog Channel Operational Test
3-OP-4004.2	Safeguard Relay Rack Train A, B, Periodic Test

4-OSP-059.4 Power Range Nuclear Instrumentation Analog Channel Operational Test

a. Non-Conservative Acceptance Criteria of Instrument Surveillance Procedures Results in Technical Specification Violation.

On January 27, 1988, a Management on Shift (MOS) observer noted inconsistencies between procedure 4-OSP-059.4, entitled Power Range Nuclear Instrumentation Analog Channel Operability Test and the Technical Specifications (TS) and the Precautions, Limitations and Setpoints (PLS) document. This concern was addressed the following day and a review of instrument surveillance procedures was initiated. This review identified instances where the instrument surveillance procedure would allow the channel to be left in a slightly non-conservative condition. The acceptance criteria in the surveillance procedures allows a reasonable tolerance from the specified TS values. Although I&C personnel would adjust the setpoints as close as possible to this TS value, the tolerance given in the procedures could result in the setpoints being slightly non-conservative. The licensee promptly initiated a review of the actual setpoint of each channel for all reactor trip and engineered safety features actuation circuits. On January 29, 1988, results indicated that four of nine steam generator (SG) level channels for low level reactor trip were left slightly below the TS setpoint of greater than or equal to 15%. No procedural tolerances were exceeded. Since two of these channels affected a single steam generator, the requirements of TS 3.5.1, Tables 3.5-1 and 3.5-2 could not be met. Consequently, the unit entered TS 3.0.1 and a shutdown was initiated. The licensee approached the NRC concerning application of discretionary enforcement for this situation. The licensee applied for a 24 hour extension of TS 3.0.1, which would allow full power operation while the instrument setpoints were adjusted. The justification for the extension was presented by the licensee and discretionary enforcement was granted by the NRC, Region II.

The licensee then performed calibrations to return the instrument channel setpoints to the current TS requirements. The setpoints were adjusted within 24 hours of entering TS 3.0.1. The licensee provided instructions to the I&C Department to ensure notification of the I&C Supervisor prior to any maintenance on the affected instruments. The affected procedures have been revised to ensure that the acceptance criteria and related tolerances comply with the limits specified in the current TS. The licensee provided a written technical justification for the request of discretionary enforcement via letter L-88-54, dated February 3, 1988. This letter outlined the circumstances surrounding this issue along with the corrective measures taken.

The conditions described above constitute a violation of TS 3.5.1, Tables 3.5.1 and 3.5.2. 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 that this violation meets the criteria of 10 CFR 2, Appendix C; therefore, no notice of violation will be issued.

b. Unit 4 Engineered Safeguards Integrated Test

On February 12, 1988, the licensee conducted the Unit 4 Engineered Safeguards Integrated Test, in order to satisfy the requirements of TS, sections 4.1, 4.5.1, 4.6.1, 4.7.1, 4.7.3 and 4.8.1. The test is divided into two sections. The first section consists of initiating a Loss of Offsite Power (LOOP). The licensee then verifies that the Emergency Diesel Generators (EDG) start and energize the 4KV busses and the sequencers load the vital equipment on to the busses. The critical data is collected and the normal power supplies are realigned in preparation for the next section of the test. The next section consists of a LOOP followed by a Safety Injection (SI) signal. The LOOP equipment is then verified to have sequenced on to the bus and at a count of 60 seconds after LOOP initiated, a SI is initiated by simulating a high and high-high containment pressure. The SI equipment is then verified to be sequenced onto the busses. The remainder of the test includes the EDG full load rejection, manual SI actuation, and performing manual containment phase A and B isolation actuation. The following items were noted during the performance of the test:

(1) Breaker 40535, feed for Motor Control Center (MCC) 4A nonvital section did not open. This was evaluated by engineering and it was determined that monitoring of this breaker is not required during this test. PC/M 86-096 revised the source of feed for MCC 4A to Load Center (LC) breaker 40103. As a result, the shunt trip feature of breaker 40535 is not relied upon.

(2) Non vital section of MCC D tripped (breaker 0832 opened). Engineering determined this occurred as designed and this normal event should be included in the test procedure.

(3) Agastat timer 2X2A for the 4A sequencer was not within its allowable setpoint of 35 to 36 seconds. The timer was reset by the electrical department.

(4) 4A Emergency Containment Filter (ECF) and 4A Emergency Containment Cooler (ECC) failed to start after SI actuation. This condition is per design. On the Spot Change (OTSC) 5730 was written to delete section 7.3.26, steps 9 and 18, and to add a test of the 4A ECF and ECC start circuits. These circuits were successfully tested on February 13, 1988.

No violations or deviations were identified within the areas inspected.

7. Maintenance Observations (62703/62700)

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:

(1) Troubleshooting and Repair of the Station Battery Chargers (see paragraph 7.a.).

(2) Replacement of AFW Auxiliary Steam Supply Valve 4-080 (See paragraph 7.b.).

(3) Preparation for the Repair of RCP 3C Seal.

(4) Installation of the Reactor Vessel Head Area Leakage Detection System for Unit 3.

(5) Repair of CRDM D-8 Canopy Seal Weld Leak.

(6) Troubleshooting Unit 4 Turbine Control Oil System and Stub Shaft Replacement.

a. Troubleshooting The Station Battery Charger Failures.

On February 6, 1988, at 1015, the 4S station battery charger was taken out-of-service in order for the Electrical Department to perform routine quarterly maintenance. The chargers are a constant voltage Float Charger manufactured by Exide Electronics. The 3B, 4A and 4S chargers are Model UPC 300 amp and the 3A, 4B and 3S are Model US 400 amp chargers. Maintenance was conducted in

accordance with 0-SME-003.6 (125 VDC Station Battery Charger Quarterly Maintenance) and completed at approximately 1435 on the same day. While attempting to return the charger to service, electrical arching and smoke was observed issuing from the charger. The charger was immediately de-energized and declared out-of-service. Subsequent inspection revealed that two of six identical printed circuit cards were visibly damaged. The 4S charger was then repaired by replacing the two damaged cards and returned to service satisfactorily at about 1410 on February 7, 1988. Then, the 3B charger was removed from service to perform the same quarterly preventative maintenance per 0-SME-003.6. As the charger was removed from service, an electrical popping sound was heard and the initial inspection showed that two of the six circuit cards in this charger had failed similarly to the cards in the 4S charger. The licensee immediately performed a visual inspection of the 4A charger, which still remained on line. This inspection indicated that one of the six cards had visibly failed, however, the charger still appeared to be functioning properly.

The licensee then considered the 3B and 4A battery chargers out of service and commenced a unit shutdown at 1645 on February 7, 1988. The licensee also made a 10 CFR 50.72 report under section (b)(1)(i)(A) although their current licensed Technical Specifications did not require a unit shutdown, as it requires only four out of six chargers available. The licensee opted to shutdown to investigate and implement repairs in accordance with the more conservative Standard Technical Specifications, currently under NRC review, which would require the unit be placed in a 24 hour LCO.

Investigation into the failures indicated that as a result of the implementation of a vendor wiring modification identified in PC/M 87-344, 18 Gate Filter Module cards were replaced on the 3B, 4A and 4S battery chargers in late 1987. After this modification the plant began experiencing random failures of the C3 snubber capacitor on these cards during the performance of 0-SME-003.6, as discussed above. This capacitor was not the subject of the above referenced modification but was mounted on the same printed circuit card. The subject capacitors are used in a "snubber" circuit to dampen the effects of transients on the battery charger silicon controlled rectifiers (SCRs).

The licensee contacted the vendor (Exide Electronics) on February 7, 1988, to aid in determining the root cause of the failures. The results of this discussion (which is documented in a letter from the

vendor to the licensee dated February 8, 1988) indicated the following:

- The original capacitor used for C2 was discontinued by the manufacturer that supplied the part to Exide Electronics. The replacement capacitor selected by Exide Electronics met all published parameter of the original capacitor. Recently, the vendor discovered the replacement capacitor selected was not recommended for snubber applications and might fail when subjected to transients. The replacement capacitor was installed on some of the circuit boards replaced during the implementation of PC/M 87-344. All the capacitors that failed were of the new replacement type. A visual inspection by the inspectors indicated that although the original and replacement capacitors had the same specifications, the original capacitors appeared to be more "heavy duty". The vendor subsequently selected a new capacitor that is designed specifically for "snubber" circuit applications and provided the licensee with new circuit boards containing these capacitors.

- The vendor also indicated the failures that occurred could have been aggravated by the sequence of operation of the equipment. The method used by the licensee to remove an operating charger from service was to open the output, or battery breaker, to isolate the charger, followed by opening the AC input breaker. The vendor stated that this sequence of operation creates a large transient on the SCR power circuit due to the sudden unloading of the charger, which could destroy the snubber capacitor immediately, or result in the capacitor failing at a later date. The method for removing a charger from service, as stated by the vendor, is by first opening the AC input breaker to shutoff the charger, and then opening the battery breaker to isolate the unit.

- The vendor considered that utilizing the newly supplied circuit boards with a capacitor designed for snubber applications and using the proper method of operation would eliminate the failures.

Discussions with responsible licensee engineers indicated that they considered the root cause of the failures to be the capacitors, which were not recommended for "snubber" circuit applications. Their method for removing and returning a charger to service had been used for many years in the past without circuit card failure. The failures did not start until the cards with the replacement capacitors were used in the charger.

The inspector reviewed the vendor Technical Manual supplied with the chargers and could find no instructions for removing a charger from service. The manual (Instruction Manual For Exide Battery Chargers - Model UPC-130-3-300) did contain instructions for placing a charger

in service, however, the instructions were not clear to the inspector. The inspector considered the vendor manual to be vague in stating the method of operation when compared to the licensee's recent communications (verbal and followup letter) with the vendor concerning this issue.

The licensee modified their procedure (0-OP-003.1, 125V Vital DC System) to be consistent with the vendors latest recommendations for removing and returning a charger to service. New circuit cards containing the new type C2 capacitors were installed, then the chargers were inspected and tested in accordance with the vendors instructions and Design Equivalent Engineering Package (DEEP) PC/M 88-050.

b. Auxiliary Feed Water Steam Supply System Water Accumulation.

At 1945 on January 20, 1988, when "A" AFW pump turbine was aligned for testing after maintenance, an excessive amount of water was drained from the steam supply line through the steam trap by-pass. This condition would be normal when releasing an AFW turbine from clearance, if any steam leakage existed in the upstream steam supply portion of the system, as the manual isolation valves to the turbines are near the turbines and are a low point in the steam supply system. Thus, any steam leakage past the upstream stop valves would condense and cause water to be trapped at the manual isolation valves just upstream of the turbines. When the isolation valves are later opened for testing and normal standby lineup, a slug of water trapped by the manual isolation valves could enter the turbine. The piping downstream of the manual isolation valves is provided with a high pressure drain (HPD) trap upstream of the turbine inlets. The discharge from the HPDs can be directed to the main condenser of either unit or bypassed to floor drains. In addition, the turbine is provided with leak off lines for moisture from the trip and throttle valve, turbine casing.

After draining the excessive water the operators identified a concern that the traps are capable of being lined up to either unit's condenser through balance of plant (BOP) piping downstream of the traps. If the traps were lined up to a shutdown unit via the downstream piping they might be ineffective due to a lack of vacuum in the shutdown unit and the various elevations in the piping run to the condenser. This was the case when Unit 3 was shutdown and Unit 4 was at 100% power, with the AFW traps aligned to Unit 3. Based on this concern Operations Department requested that the system engineer and the Procedures Upgrade Program Department check on modifying the unit General Operating Procedures to ensure the AFW traps are lined up to the operating unit's condenser.

No procedures were available for controlling the BOP lineup downstream of the traps and no controlled drawings showed the piping and valve configuration in that portion of the system. Operations

Department personnel subsequently realigned the AFW traps to Unit 4 condenser using a clearance to control valve positions.

The licensee stated that they were in the process of determining the source of the water by determining which upstream isolation valve was leaking prior to the Unit 4 shutdown on February 7, 1988. The licensee indicated that the most likely source was seat leakage from valve 4-080. This valve was subsequently replaced during the Unit 4 outage. The inspectors examined the removed valve and the body seats showed signs of gross pitting. The disc seats showed signs of steam leakage and some pits, although not as bad as those in the valve body.

The licensee does not consider water in the steam supply piping to be an operability concern. The licensee indicated that the large amount of water drained from train 1 on January 20, 1988 was due to the "A" AFW turbine being isolated for maintenance and the 4-080 valve leaking by its seat. Subsequent repairs to the 4-080 valve should prevent recurrence of this problem. Maintaining the traps aligned to the operating units condenser should remove any moisture or condensation prior to entry into the turbine. The licensee also stated that the design of this turbine (Terry Turbine), could accommodate a slug of water without damaging the turbine. This was confirmed by telephone between the licensee and the vendor. The vendor agreed to provide written confirmation to the licensee.

Water was trapped in the steam supply to the "A" AFW turbine because of an abnormal valve alignment during maintenance. However, the same condition normally exists for "B" AFW turbine. This is because the train 1 manual isolation valves for the "B" AFW turbine are normally locked closed and the normal steam supply is from train 2. The Inspector's concern was that the "B" AFW turbine could be lined up to Train 1 creating the same water problem observed with the "A" turbine. The licensee addressed this concern as follows:

The licensee considered that periodic draining of the train 1 header to the "B" turbine was unnecessary because:

This section of piping always remains isolated. Although piping configurations could allow the "B" AFW turbine to be aligned to Train 1, the licensee currently has no procedures or plans to perform this evolution. Therefore, the water would remain undisturbed in the train 1 steam piping.

If the water were periodically drained from this dead leg, this section of piping would fill again subsequent to normal system operation. The licensee does not consider the water in the piping to be detrimental to the piping or valves in regards to corrosion.

The following actions are underway to ensure the traps are lined up to an operating unit's condenser.

The traps were aligned to Unit 4 under a clearance.

The system engineer performed a "hand-over-hand" walkdown of the BOP portion of the system downstream of the traps and produced a draft drawing of the system. A copy of this drawing was provided to engineering with a request to provide a controlled drawing with valve numbers for this portion of the system. This will be accomplished under REA 88-74.

When the controlled drawing is completed, procedures will be updated or created to control the valve lineups in this section to ensure traps are lined up to an operating condenser.

As an interim control, until the drawings are upgraded, the Operations Superintendent and System Engineer stated temporary controls will be added to the procedures to ensure the traps are lined up to an operating unit. The inspectors will followup on this issue during future inspections.

8. Engineered Safety Features Walkdown (71710)

The inspectors performed an inspection designed to verify the operability of the Unit 3 Safety Injection and Residual Heat Removal (RHR) systems by performing a walkdown of the equipment located primarily inside the Unit 3 containment building. The following criterions were used, as appropriate, during this inspection:

a. System 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.

The inspectors reviewed procedure 3-OSP-050.4 entitled RHR System Flowpath Verification While in RHR Cooldown Operation, revision dated December 18, 1987, and operating diagram 5610-T-E-4510, Sheet 2, revision 6, on Safety

Injection and Residual Heat Removal Systems inside Containment. Minor discrepancies identified by the inspectors were brought to the attention of the licensee and corrected.

No violations or deviations were identified within the areas inspected.

9. 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
Unit 3 and 4 Component Cooling Water
Unit 3 and 4 Containment Spray Pumps
Unit 3 and 4 Refueling Water Storage Tanks
Unit 3 and 4 Primary Water Storage Tanks

On February 5, 1988, with Unit 3 in cold shutdown, the inspectors observed that all 3 operable ICW basket strainers had indications of high DP. The fourth strainer, located in train 3B to the CCW heat exchangers, had been out of service since January 22, 1988 and was isolated from system flow by

closed inlet and outlet valves. The DPs associated with each basket strainer are indicated as follows:

Strainer	Component Number	DP Reading	Deficiency tag date
ICW/TPCW 3A	3-1400	3.0 psid	1/29/88
ICW/TPCW 3B	3-1401	3.0 psid	none present
ICW/CCW 3A	3-1402	3.0 psid	1/17/88
ICW/CCW 3B	3-1403	out of service	1/4/88

Since high DP is indicative of reduced ICW flow, an attempt was made to verify flow by observing installed meters. The 3 flow meters located at the discharge of the CCW heat exchangers were found to have been removed. The NRC inspectors were concerned that ICW flow through the CCW heat exchangers might be degrading and the condition might not be identifiable due to the absence of the flow meters and the partially obstructed condition of in-service strainer 1402. This concern was discussed with the Plant Supervisor Nuclear (PSN) on the evening of February 5, 1988. The PSN was aware that ICW basket strainer 1403 had been out of service for 14 days and that the flow indicators were not installed. However, he determined that normal ICW flow through the heat exchangers had been measured earlier in the day (using a portable test gauge) during a surveillance test. Additionally, he noted that ICW and CCW system temperatures were normal. Consequently, the PSN had no immediate concern for system operation. However, he agreed that strainer 1403 should be restored to operation expeditiously so that strainer 1402 could be cleaned. Cleaning both strainers simultaneously is not possible because one ICW train must remain in service at all times to provide a heat sink during shutdown cooling.

Basket strainer 1403 was returned to service on the morning of February 6, 1988. However, basket strainer 1402 was not taken out of service for cleaning. Additionally, basket strainer 1403 began to rapidly foul. During the first 12 hours after being returned to service, the DP indicator for strainer 1403 increased from 0.6 psid (1:00 pm logs) to full scale (1:00 am logs). Additionally, ICW system pressure at the TPCW heat exchangers remained at 12 psi, which is above the designated band of 3 - 9 psi.

These trends were not recognized by licensee personnel as indicative of ICW flow reduction. By the morning of February 7, 1988, all four strainer DP indicators had been above their allowable bands for extended periods of time. At approximately 9:30 a.m. the discharge pressures of the two operating ICW pumps increased from the normal value of 22 psig to 30 psig. Recognizing this as an unusual event, an Auxiliary Nuclear Plant Operator (ANPO) alerted control room personnel who directed that strainer 1402 be immediately cleaned. The PSN directed that one of the two operating ICW pumps be turned off. This action reduced but did not eliminate the symptoms of high strainer DP and high pump discharge pressure. Two and one half hours elasped before strainer 1402 was taken out of service for cleaning.

The 8 psig increase (from 22 to 30 psig) in ICW pump discharge pressure observed on February 7, 1988, represented a drop in pump flow of approximately 50%. This flow reduction did not adversely affect shutdown cooling temperatures. However, it constituted an undersirable condition because it occurred without the knowledge of the plant staff. Additionally, strainer fouling through seaweed accumulation is undesirable because the reductions in flow rates are sporadic, of unpredictable magnitude, and are not quickly reversible.

The ICW system is essential to the operation of the shutdown cooling system. Monitoring equipment such as flow indicators, differential pressure indicators and discharge pressure gauges must remain operable to provide the capability to trend system performance. Operation of the strainers with full scale or off-scale DP indications precludes trending, as does operating the system without installed flow gauges. In summary, the strainers became excessively fouled because data obtained during logging evolutions performed at the CCW and TPCW heat exchangers was not examined in sufficient detail to allow identification of the developing condition.

Between January 15 and February 11, 1988, Unit 3 was operating in mode 5, cold shutdown. Consequently, the ICW and CCW systems were not being used to remove large heat loads. The degraded status of the ICW system was resolved before it resulted in increased system operating temperatures. Therefore, the described events did not threaten the health and safety of the public. Nevertheless, the event constitutes an inspector concern because of the potential addresses affects of excessive strainer fouling which could occurr if the strainers are not properly monitored during power operations. This concern was discussed in detail with senior members of the licensee's management team.

The following list summarized ICW system discrepancies which existed prior to the observation of degraded flow:

a. 3B CCW heat exchanger strainer 1403 was first observed to be fouled on January 4, 1988 and a PWO was written for cleaning. However, cleaning did not begin for 18 days.

b. 3A CCW heat exchanger strainer 1402 was first observed to be fouled on January 17, 1988. Strainer 1403 had been fouled for a longer period of time so it was selected to be cleaned first, on January 22. During that cleaning, maintenance deficiencies were identified but repairs were not expedited. Two weeks were required to complete tasks which can be completed in a day or two.

c. Flow meters 3-1407 and 3-1409, monitoring ICW flow through two of three CCW heat exchangers were physically removed from the system, without administrative authorization, prior to the Spring of 1987. A third flow meter (3-1408) was removed in October 1987 as authorized

by a Temporary System Alteration (TSA) 3-87-19-76 in accordance with administrative procedure O-ADM-503. Removal of two flow meters without implementing the requirements of procedure O-ADM-503 is one of three examples of violation (250, 251/88-02-01).

d. Log sheets for ICW system flow through the TPCW and CCW heat exchangers specify only a maximum flow rate. A minimum acceptable flow rate should also be specified so that observation of degraded flow can be recognized and acted upon.

e. A caution tag was issued on February 2, 1988, in accordance with Administrative Procedure 0103.41, revision 12/11/86, requiring that the equalizing valve (3-449) for the DP indicator for strainer 1402 be kept open. This action prevented the existing off-scale high DP condition from damaging the DP indicator which had just recently been replaced and calibrated. On February 5, 1988, NRC inspectors found valve 3-449 closed. The valve was promptly reopened by licensee personnel. The failure to keep valve 3-449 opened in accordance with AP 0103.41 is another example of violation 250, 251/88-02-01.

f. The acceptable values for ICW pump discharge pressure indicated on the plant logsheets was 17-50 psig. A review of the ICW pump curves revealed that 50 psig discharge pressure equates to less than 2,000 gpm flow. This value is far less than the 16,000 gpm assumed to be supplied by a single ICW pump during design basis accident conditions considered for operational plant modes. Additionally, the acceptance criteria for system flow was specified on the logsheets only as "less than or equal to 8,000 gpm per heat exchanger". Greatly reduced flows would not fall outside this acceptable value. Consequently, during power operation, the observation of low system flow might not have been recognized as a significant indicator of degraded system performance. The failure to have adequate acceptance criteria for procedure O-OSP-201.4 is the third example of violation 250, 251/88-02-01.

10. 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. The licensee plans to issue Licensee Event Report (LERs) on each event within 30 days following the date of occurrence.

On February 1, 1988, with Unit 4 at 100% power, the unit experienced a partial loss of load (approximately 220 MWe) due to a sudden increase in impeller oil pressure. The impeller oil pressure had been erratic over the previous four to five days. The pressure had dropped to 27.5 psig. At 0305, On February 1, 1988, the Reactor Control Operator (RCO) received annunciators for steam dump; steam generator level deviation, feed/steam flow mismatch with a rapid load decrease. The impeller oil was found to be at 29.5 psig. The licensee determined that the sudden increase in impeller oil pressure caused the control oil to dump from 47 psig to 37 psig which resulted in the decrease in load. The cause of the changes in impeller oil pressure was attributed to wear on the Stub Shaft. It is believed that impurities in the oil caused grooving in the shaft which caused the oil pressure to fluctuate. The Stub Shaft was subsequently replaced and the unit was returned to service on February 24, 1988.

On February 7, 1988, with Unit 4 at 100% power, the licensee identified failed circuit cards in the 3B and 4A battery chargers. The two battery chargers were declared out of service. Although the current Turkey Point Technical specifications (TS) permit operation with two battery chargers out of service. It would not be permitted under the proposed TS. The licensee followed the more conservative TS and Unit 4 was shutdown. This item is discussed in further detail in paragraph 7.

On February 19, with Unit 3 in Mode 3 and Unit 4 in Mode 5, water was discovered on the floor of the 4A 4160 volt switchgear room. The source of the water was found to be from the overhead air conditioning duct. The room was roped off and the bus was de-energized in order to inspect the breaker cubicles and perform any necessary corrective actions. The electricians found a number of cubicles containing water and the cubicles were subsequently dried. On February 20, at 0215, the electrical buses were returned to normal operation. The licensee took corrective actions to prevent recurrence which include:

a. Inspecting all other electrical components with air conditioning ductwork running overhead to verify proper installation and also that no water is leaking.

b. The 4A 4160 volt switchgear room duct work was immediately repaired.

c. Periodically inspect all areas of concern identified, during the inspection of the other electrical components, until repairs have been made.

On February 20, 1988, with Unit 3 in Mode 3 and Unit 4 in Mode 5, the licensee reported a significant event at 1150, due to the Emergency Notification System (ENS) phone being out of service. The proper notifications were made and the phone was returned to service at 1320 on the same day.