UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-250/94-13 and 50-251/94-13

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

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

Facility Name: Turkey Point Units 3 and 4

Inspection Conducted: July 3 through 30, 1994

Inspectors: _____ 8/12/94
T. P. Johnson, Senior Resident Inspector Date Signed

_____ 8/12/94
B. B. Desai, Resident Inspector Date Signed

_____ 8/12/94
L. Trocine, Resident Inspector Date Signed

Accompanied by: R. P. Schin, Project Engineer, Reactor Projects Section 2B, Division of Reactor Projects

Approved by: _____ 8/17/94
for K. D. Landis, Chief Date Signed
Reactor Projects Section 2B
Division of Reactor Projects

SUMMARY

Scope:

This resident inspection was performed to assure public health and safety, and it involved direct inspection at the site in the following areas: plant operations including operational safety and plant events; maintenance including surveillance observations; engineering; and plant support including radiological controls, chemistry, fire protection, and housekeeping. Backshift inspections were performed in accordance with Nuclear Regulatory Commission inspection guidance.

Results:

Within the scope of this inspection, the inspectors determined that the licensee continued to demonstrate satisfactory performance to ensure safe plant operations. The following violation and non-cited violation were identified:

Violation 50-250,251/94-13-01, Missed Valve Inservice Tests (section 5.2.4)

Non-cited Violation 50-250,251/94-13-02, Unescorted Visitors Within the Protected Area (section 7.2.1)

During this inspection period, the inspectors had comments in the following Systematic Assessment of Licensee Performance functional areas:

Plant Operations

Although maintenance cleaning activities caused the loss of the non-vital 3A motor control center; license response was aggressive, timely, and ensured safe plant operation (section 4.2.1). Operators' logs appeared effective in documenting unit operations (section 4.2.2). Company Nuclear Review Board members displayed a very good questioning attitude and a pro-active approach to nuclear safety (section 4.2.3). The licensee's planning, preparations, and implementation aspects for load reductions were effectively performed (section 4.2.4). Operators were knowledgeable of the plant process radiation monitoring systems, and operating procedures were appropriate (section 6.2.3).

Maintenance

The inspectors observed that station maintenance and surveillance testing activities were completed in a satisfactory manner (sections 5.2.1 and 5.2.2). Motor and bearing changeout activities for the 3B high head safety injection pump were well planned with good interdepartmental and intradepartmental coordination (section 5.2.3). A lack of attention to detail and program oversight resulted in a cited violation for numerous missed valve inservice tests; however, an excellent questioning attitude by supervision led to the discovery of this issue (section 5.2.4).

Engineering

The licensee appropriately responded to a concern that various post-accident radiation monitors would be unavailable during an accident which resulted in the shedding of non-vital power (section 6.2.1). The licensee aggressively pursued a DC ground on the control power circuit associated with the field flashing and control power for the 3A emergency diesel generator, and the followup special report was satisfactory. Further, a strength was noted in that the licensee's emergency diesel generator reliability program required a macroscopic review of emergency diesel generator problems (section 6.2.2). The system engineer was very knowledgeable of the process radiation monitor system, and procedures were appropriate. The licensee aggressively and conservatively addressed an operating experience feedback initiated issue regarding non-conservative nuclear instrumentation setpoints while at lower power (section 6.2.4). The licensee had a sound and conservative program for monitoring and maintaining component cooling water heat exchanger operability. However, a minor deficiency in the

licensee's engineering documentation was noted in that there was a lack of a written engineering evaluation to support the technical specification limit for the ultimate heat sink intake temperature. In addition, the licensee's land utilization group has been pro-active in maintaining and improving the performance of the ultimate heat sink and the cooling canal system (section 6.2.5).

Plant Support

Chemistry committed to enhancing the documentation for the process radiation monitoring system setpoints (section 6.2.3). A licensee-identified violation regarding unescorted visitors within the protected area resulted in a non-cited violation (section 7.2.1). An inspector followup item regarding the review of practice exercises with graded exercises for similarity of events and a previous inspector review regarding the height limit for climbing without fall protection were closed (sections 7.2.2 and 7.2.3).

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REPORT DETAILS

1.0 Persons Contacted

1.1 Licensee Employees

T. V. Abbatiello, Site Quality Manager
R. J. Acosta, Company Nuclear Review Board Chairman
C. R. Bible, Manager, Site Engineering
W. H. Bohlke, Vice President, Engineering and Licensing
M. J. Bowskill, Reactor Engineering Supervisor
R. J. Earl, Acting Quality Manager
S. M. Franzone, Instrumentation and Controls Maintenance Supervisor
J. E. Geiger, Vice President, Nuclear Assurance
R. J. Gianfrancesco, Maintenance Support Services Supervisor
* J. H. Goldberg, President, Nuclear Division
R. G. Heisterman, Mechanical Maintenance Supervisor
* P. C. Higgins, Outage Manager
G. E. Hollinger, Training Manager
* D. E. Jernigan, Operations Manager
* H. H. Johnson, Operations Supervisor
* V. A. Kaminskas, Services Manager
J. E. Kirkpatrick, Fire Protection/Safety Supervisor
* J. E. Knorr, Regulatory Compliance Analyst
* R. S. Kundalkar, Engineering Manager
J. D. Lindsay, Health Physics Supervisor
J. Marchese, Site Construction Manager
* F. E. Marcussen, Security Supervisor
H. N. Paduano, Manager, Licensing and Special Projects
* L. W. Pearce, Plant General Manager
M. O. Pearce, Electrical Maintenance Supervisor
* T. F. Plunkett, Site Vice President
* D. R. Powell, Technical Manager
* K. L. Remington, ISI/IST Supervisor
R. E. Rose, Nuclear Materials Manager
R. N. Steinke, Chemistry Supervisor
* M. B. Wayland, Maintenance Manager
* E. J. Weinkam, Licensing Manager

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

1.2 NRC Resident Inspectors

* B. B. Desai, Resident Inspector
* T. P. Johnson, Senior Resident Inspector
L. Trocine, Resident Inspector

1.3 Other NRC Personnel on Site

H. N. Berkow, Director, Project Directorate II-2, Office of Nuclear Reactor Regulation

R. P. Croteau, Project Manager, Turkey Point, Project Directorate II-2, Office of Nuclear Reactor Regulation
A. F. Gibson, Director, Division of Reactor Safety, Region II
J. P. Jaudon, Deputy Director, Division of Reactor Projects, Region II
K. D. Landis, Chief, Reactor Projects Section 2B, Division of Reactor Projects, Region II
R. P. Schin, Project Engineer, Reactor Projects Section 2B, Division of Reactor Projects, Region II
J. P. Stohr, Director, Division of Radiation Safety and Safeguards, Region II

* Attended exit interview on August 4, 1994

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

2.0 Other NRC Inspections Performed During This Period

Report No.	Dates	Area Inspected
50-250,251/94-16	July 11-15, 1994	Engineering Inspection

3.0 Plant Status

3.1 Unit 3

At the beginning of this reporting period, Unit 3 was operating at or near 100% reactor power and had been on line since May 27, 1994. The unit reduced power to 40% to perform testing and secondary plant maintenance on July 22, 1994. Power was returned to 100% on July 24, 1994. (Refer to section 4.2.4 for additional information.)

3.2 Unit 4

Unit 4 operated at or near 100% reactor power throughout this reporting period and had been on line since March 18, 1994. The unit reduced power to 40% on July 29, 1994, to perform testing and secondary plant maintenance. Power was returned to 100% on August 1, 1994.

4.0 Plant Operations (40500 and 71707)

4.1 Inspection Scope

The inspectors verified that FPL operated the facilities safely and in conformance with regulatory requirements. They accomplished this by direct observation of activities, tours of the facilities, interviews and discussions with personnel, independent verification of safety system status and technical

specification compliance, review of facility records, and evaluation of the licensee's management controls.

The inspectors reviewed plant events to determine facility status and the need for further followup action. The significance of these events 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 and that licensee followup including event chronology, root cause determination, and corrective actions were appropriate.

The inspectors performed a review of the licensee's self-assessment capability by including PNSC and CNRB activities, QA/QC audits and reviews, line management self-assessments, individual self-checking techniques, and performance indicators.

4.2 Inspection Findings

4.2.1 Loss of the Unit 3A MCC

On July 5, 1994, at 10.32 a.m., the feeder breaker to the 480 volt AC 3A MCC (non-vital portion) tripped open, de-energizing non-vital MCC loads. During routine maintenance housekeeping and cleaning activities in the turbine building, water was apparently sprayed or dripped into the MCC bus bars resulting in a bus short. This tripped open the 3A load center feeder breaker. The vital portion of the 3A MCC was unaffected. (The 3A vital and 3A non-vital MCCs are adjacent to each other, located on the 18 foot level (ground level) of the turbine building.

Operators received numerous control room alarms caused by the loss of the 3A non-vital MCC and the respective loads. Standby equipment appropriately started, including seal oil pumps, transformer cooling fans and pumps, ventilation equipment, etc. Other loads were lost, including normal lighting and control room remote monitoring of secondary plant equipment. The licensee responded by checking load lists; inspecting equipment; implementing operating procedure 3-OP-007, 480 Volt Motor Control Center; increasing operator round frequencies; initiating condition report No. 94-713; and informing management. In addition, power was lost to the Unit 3 air ejector condenser SPING. (Refer to section 6.2.1 of this report for further information.)

Maintenance electricians inspected and cleaned the 3A non-vital MCC, checked the breakers, and performed megger checks. These activities were successful and the 3A non-vital MCC was energized on July 6, 1994, at 6:30 p.m. per procedure 3-OP-007.

The inspectors discussed this event with licensed operators, maintenance personnel, engineers, and plant management. The inspectors noted that control room operators appropriately

responded to the loss of the 3A non-vital MCC. Conservative actions were taken to ensure plant operational effects were minimized. The inspectors observed the MCC electrical activities, noting very good management oversight and conservative personnel safety practices. The inspectors also reviewed the breaker and load lists, procedure 3-OP-007, the condition report, and electrical diagrams. The inspectors concluded that, although maintenance cleaning activities caused the loss of the MCC, licensee response was aggressive, timely, and ensured safe plant operation.

4.2.2 Operator Logs

During the period, the inspectors reviewed operator logs and logkeeping practices. Administrative procedure O-ADM-204, Operations Narrative Logbooks, revision March 24, 1994, delineated the requirements. A recent change consolidated the ANPS and RCO logs into a single narrative log with each individual making entries.

The inspectors checked logs for accuracy, legibility, actions for entry crossouts, management review, and ADM compliance. The inspectors did not identify any problems and concluded that operators' logs appeared effective in documenting unit operations.

4.2.3 CNRB Meeting No. 407

CNRB meeting (No. 407) was held at Turkey Point on July 19, 1994. The inspectors attended the meeting and verified that the following technical specification items were satisfied:

- meeting frequency per Technical Specification 6.5.2.5,
- quorum per Technical Specification 6.5.2.6, and
- review and audit items per Technical Specifications 6.5.2.7 and 6.5.2.8;

The following topics were discussed:

- plant manager's report,
- several proposed licensee amendments,
- QA program/audit status,
- NRC Inspection Report status,
- LERs, and
- plant tours.

The inspectors noted that CNRB members displayed a very good questioning attitude and a pro-active approach to nuclear safety. The CNRB members also required individuals presenting issues to be thorough and to address the safety significance of the issues. The inspectors did comment on the CNRB's process for followup of issues, including how minor issues would be tracked. Discussions were held with the CNRB Chairman. The inspectors were satisfied with the process, and had no further questions at this time.

4.2.4 Unit 3 and 4 Load Reduction For Maintenance

The licensee reduced Unit 3 load from full power to 40% power on Friday, July 22, 1994, in order to perform secondary plant maintenance and testing. This power reduction began at 7:05 p.m. and was required due to decreased performance of the main condenser and the TPCW heat exchangers. The licensee initiated plans to perform cleaning of condensers and heat exchangers as well as other items. The periodic turbine valve test, steam generator feedwater pump and heater drain pump work, valve maintenance, and other related items were performed. The unit was returned to full power on July 24, 1994, at 5:30 p.m.

Unit 4 load was also reduced to 40% on July 29, 1994, for TPCW cleaning and turbine valve testing. The unit was returned to 100% power on August 1, 1994.

The inspectors reviewed the detailed plan and discussed it with licensee personnel. The inspectors also witnessed portions of the maintenance and testing activities and the unit power changes. The inspectors concluded that the licensee's planning, preparations, and implementation, aspects of these load reductions were effectively performed.

5.0 Maintenance (62703 and 61726)

5.1 Inspection Scope

The inspectors verified that station maintenance and surveillance testing activities associated with safety-related systems and components were conducted in accordance with approved procedures, regulatory guides, industry codes and standards, and the technical specifications. They accomplished this by observing maintenance and surveillance testing activities, performing detailed technical procedure reviews, and reviewing completed maintenance and surveillance documents.

5.2 Inspection Findings

5.2.1 Maintenance Witnessed

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

- WR 9401756801, 3C charging pump packing leak repairs;
- WR 94016005, RWST recirculation isolation valve MOV 4-856A grease inspection;
- 4B ICW pump changeout activities;
- 3A1 circulating water pump replacement;
- 3B steam generator feedwater pump breaker maintenance;
- 3A MCC cleaning and inspections (Refer to section 4.2.1 for additional information.); and
- 3B HHSI pump motor and bearing replacement (Refer to section 5.2.3 for additional information).

For those maintenance activities observed, the inspectors determined that the activities were conducted in a satisfactory manner and that the work was properly performed in accordance with approved maintenance work orders.

5.2.2 Surveillance Tests Observed

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

- procedure 3-SMI-041.11, Pressurizer Level Protection Loop Quarterly Test; and
- procedure 4-OSP-206.2, Quarterly Inservice Valve Testing.

The inspectors determined that the above testing activities were performed in a satisfactory manner and met the requirements of the technical specifications.

5.2.3 3B HHSI Motor Replacement

The 3B HHSI motor was replaced to enable the inspection of the old motor to determine whether or not the presence of rotor bar cracks exists. The inspectors observed portions of activities associated with the 3B HHSI motor and bearing changeout. The system was returned to service well within the 30-day technical specification action statement and several hours ahead of the planned schedule. The old motor will be shipped to the manufacturer for inspection.

The inspectors determined that the activity was well planned with good interdepartmental and intradepartmental coordination. Minor problems relating to pump rotating element alignment encountered during the evolution were appropriately dispositioned.

5.2.4 Missed Technical Specification Required Surveillances

On July 21, 1994, the licensee discovered that a number of technical specification required quarterly surveillances involving valve exercising were not performed. The systems affected included: the Unit 4 EDG fuel oil system, the Units 3 and 4 RHR systems, and the Units 3 and 4 CVCS systems. Upon identification, operability of the affected system was confirmed by ensuring that all the involved valves had been successfully exercised during a subsequent quarterly surveillance. The resident inspectors were notified and a thorough investigation was initiated to determine the circumstances surrounding the missed surveillances. A condition report (No.94-0740) was also initiated by the licensee.

The valves that had not been exercised, the procedures used to exercise the valves, and the dates during which the surveillance test procedures were not performed were as follows:

VALVES	PROCEDURE	DATES NOT PERFORMED
SV-4-3434A, SV-4-3434B	4-OSP-022.4, EDG Fuel Oil Transfer Pump and Valve IST	January 1993, July 1993, and January 1994
CV-3-200A CV-3-200B CV-3-200C CV-3-310A CV-3-310B	3-OSP-047.1, Charging Pump/ Valves IST	May 1993 and February 1994
CV-4-200A CV-4-200B CV-4-200C CV-4-310A CV-4-310B	4-OSP-047.1, Changing Pump/ Valves IST	February 1994
MOV-3-860A MOV-3-860B MOV-3-861A MOV-3-861B	3-OSP-050.2, Residual Heat Removal system IST	May 1993 and August 1993
MOV-4-860A MOV-4-860B MOV-4-861A MOV-4-861B	4-OSP-050.2, Residual Heat Removal system IST	April 1994

The above listed valve's functions are as follows:

- SV-3434A and B are located at the discharge of the EDG fuel oil transfer pump within the 4A and 4B EDG building and are required to open to maintain fuel oil inventory in the day

tanks. A manual valve and flowpath exists around both the valves.

- CV-200A, B, and C are letdown/containment isolation valves located in the containment and are required to shut on phase A containment isolation. A redundant isolation valve outside containment also exists.

- CV-310A and B are located in the containment and are required to open or stay open to maintain charging flow. Normally one of the two charging valves is always open.

- MOV-860A and B and MOV 861A and B are located in the auxiliary building and are required to open for the RHR sump recirculation mode of ECCS operation. High radiation levels following an accident would make it difficult to manually open these MOVs.

The above mentioned valves are required to be tested per the surveillance requirements of Technical Specification 4.0.5 in accordance with ASME Section XI. Specific testing criteria for each of the valves is described in the current 10 year IST program. The 10 year IST program dated October 28, 1993, is implemented by O-ADM-502, In-service Testing Program, which delegates the administration, coordination, and maintenance of the IST program responsibilities to the IST coordinator. O-ADM-215, Plant Surveillance Tracking Program, controls the computerized tracking and scheduling aspects of the required surveillances. Operations surveillance procedures (OSPs) provide the instructional guidance and valve test method to satisfy this requirement of the technical specifications and O-ADM-502. The failure to perform the above mentioned OSPs as required by Technical Specifications 4.0.5.a is considered a Violation 50-250,251/94-13-01, Missed Valves Inservice Test. Although this violation was licensee identified, it is being cited due to the extent and number of the missed valve tests.

The IST coordinator is relied upon to ensure completion of testing requirements at the required frequency. The IST coordinator works with the operations scheduler to ensure that the surveillance is scheduled and indicated on the surveillance tracking sheet. This surveillance tracking sheet is the basis for the control room operator to perform a particular surveillance test. The IST coordinator also fills out the acceptance criteria prior to performance of the OSP.

The NPS reviews the OSP and authorizes initiation of the OSP. Upon completion, the NPS again reviews the OSP and the completed OSP is then returned to the IST coordinator for his review. The IST coordinator reviews the OSP and extracts pertinent data needed for trending purposes. A feedback to the surveillance planning

and scheduling group to ensure that updating of the computerized surveillance tracking system occurs.

In each of the missed surveillances mentioned above, the OSP, in addition to the valve IST, also included the instructional guidance and method for the testing of system pumps. For example, sections 7.1 and 7.2 of 4-OSP-022.4 involved testing of the EDG diesel oil transfer pumps and section 7.3 involved testing of the solenoid valves associated with the 4A and 4B EDG Fuel Oil transfer line to the day tank. Similarly, the pump and valve testing for the other OSPs mentioned above are established in different sections within the same OSP. It is postulated that the valve surveillances were missed because the appropriate section involving valve IST in the OSP were not performed. The pump ISTs had been completed. However, the licensee could not locate completed sections associated with valve exercising, indicating that the valve tests were not performed.

The problem was recognized by the ISI/IST group supervisor when questioned by the control room operator about whether section 7.3 of surveillance OSP-022.4, involving valve testing, needed to be performed. The supervisor initiated a quick review of completed OSPs. During the review, several completed OSPs were noted to not have the section associated with the valve ISTs. Consequently, a broader review encompassing all OSPs scheduled during the past two years was performed.

During this review, the licensee identified that nine technical specification required surveillances had not been fully performed since January 1993. This resulted in a total of approximately 33 inservice tests, affecting 20 valves, not being performed.

Upon identification of the missed in-service valve tests, the licensee immediately verified that subsequent quarterly tests had been successfully performed. In addition, work history on the valves was reviewed to identify if any maintenance had been performed on the valves during the period that the valves were not tested. It was determined that no maintenance had been performed. The valve trend data was also reviewed and found to have missing data points for the missed ISTs.

Following this review, the licensee concluded that no operability issues relative to the valves or the affected systems existed. However, it should be noted as a result of 3 OSP-050.2 and 4 OSP-050.2 not being fully performed, recirculation portions of both the redundant RHR trains were not tested as required on both units. Additionally, on Unit 3, the redundant RHR valves were not tested for two consecutive quarters. Similarly, valves on the fuel transfer lines to the day tanks for both 4A EDG and 4B EDG were not tested on three occasions between January 1993 and January 1994. However, these valves were tested satisfactorily during periodic EDG testing.

As a result of this issue, the following corrective actions are planned or were completed by the licensee:

- operability of the affected valves/systems was verified;
- a condition report was initiated to determine the root cause(s) that led to the problem;
- a review of operations logs and operator interviews were conducted;
- a Licensee Event Report will be issued detailing the circumstances, significance, and corrective actions associated with the problem;
- QA was requested to perform an independent review and analysis of the problem;
- responsibility assignments were initiated;
- actions were initiated to determine if similar problems exist in the other disciplines including ISI, I&C, electrical, mechanical; and
- actions were or will be initiated to determine magnitude and type of program and computer tracking enhancements to preclude recurrence.

The inspectors verified that the subsequent quarterly surveillances had been successfully completed and that no past operability issues existed. The inspector concluded that the IST program was not effectively implemented, including final review of the completed surveillance procedures. For the instances during which the valve surveillances were not performed due to a misunderstanding, the operators returned only the completed pump sections of the surveillance procedure to the IST coordinator. However, the IST program review did not recognize that the valve sections were missing. Additionally, this resulted in the data needed to trend the valve stroke times not being available. This was also not recognized during subsequent valve stroke time data input into the trending program.

Several issues came to light as a result of this problem. Most significant of this was the heavy reliance on a single individual and a lack of adequate program oversight to assure the adequate implementation of the IST program. In addition, in the inspector's judgement, there were several opportunities during which the surveillance problems could have or should have been identified. These included, identification by the NPS during his review and signoff on the OSP and identification by the system engineer during his review of system status and trend data.

The inspectors also noted some inconsistences in the surveillance tracking system. Specifically, the surveillance tracking sheet used by the operators to initiate a scheduled surveillance does not always identify specific sections that need to be performed. This may have led to some confusion on part of the operators as the pump and valve testing are incorporated in different sections. Therefore, the operators frequently called the IST coordinator to determine which sections needed to be performed.

The inspectors discussed the issue as well as the planned corrective actions with the licensee. The inspectors recognized the questioning attitude that resulted in the identification of the problem.

6.0 Engineering (37551)

6.1 Inspection Scope

The inspectors verified that licensee engineering problems and incidents were properly reviewed and assessed for root cause determination and corrective actions. They accomplish this by ensuring that the licensee's processes included the identification, resolution, and prevention of problems and the evaluation of the self-assessment and control program.

6.2 Inspection Findings

6.2.1 Post-Accident Instrumentation

As followup to the inadvertent loss of the Unit 3 3A non-vital MCC (section 4.2.1), the inspectors noted that the Unit 3 air ejector SPING lost power. Operators appropriately entered the action statement for Technical Specification 3.3.3.3 and Table 3.3.5, item 19. Based on inspector concerns that the air ejector SPING post-accident monitor was not powered by vital power, the licensee initiated condition report No. 94-715. The inspectors reviewed breaker and load lists, and confirmed that the vent stack, both unit air ejectors, the Unit 3 SFP vent, and the main steam line radiation monitors were all partially powered from various non-vital distribution panels.

NRC Regulatory Guide 1.97, Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, Revision 3, Table 3, requires that radioactive release monitors be category 2, type C, variables. Per Table 1 of the regulatory guide a category 2 variable requires that this instrumentation be energized from a high-reliability power source (not necessarily standby-power) and that it should be backed up by batteries if momentary interruption is not tolerable. Further, UFSAR Table 7.5-1 confirms that these aforementioned post-accident radiation monitors are category, 2 type C variables, with power from plant

inverters and backed up from safety-related batteries. However, detectors, micro-processors, and sample pumps are powered from non-vital sources, with backup from the EDGs or blackstart diesels.

The inspectors expressed a concern that these post-accident radiation monitors would be unavailable during an accident (LOCA, LOOP, or LOOP-LOCA) which resulted in the shedding of non-vital power. License engineering and operations personnel responded to this concern, as documented in the CR response. They concluded that current licensing basis was met, and that existing operating procedures where adequate to energize the appropriate non-vital buses for operation of radiation monitors. However, the licensee made OTSCs to the appropriate operating procedures to better assure availability of the radiation monitors. Further, as part of standby steam generator feed pump modification (which eliminates the need for the blackstart diesels), the licensee intends to repower the affected radiation monitors from a vital power supply. The inspector verified these actions, and had no further questions.

6.2.2 3A EDG Failure and Related Issues

At approximately 8:50 p.m. on July 2, 1994, the Unit 3 control room received a DC ground annunciator alarm. The DC ground was traced to the control power circuit associated with the field flashing and control power for the 3A EDG. The ground was narrowed to an electronic speed switch located within the idle start cabinet. A licensee inspection of the speed switch revealed that the power supply internal to the speed switch had a burnt component. The speed switch was replaced, and the 3A EDG was successfully tested and declared operable after being out of service for 27 hours and 10 minutes. A condition report (No. 94-710) associated with this event was also initiated.

The functions of the speed switch include a permissive to initiate field flashing at 800 rpm and also to initiate an EDG lockout if the EDG is not at 800 rpm within 15 seconds of the start signal Therefore, the failure of the speed switch would have prevented the 3A EDG from performing its intended safety function if called upon. The licensee classified this as a non-valid failure of the 3A EDG per technical specification 4.8.1.1.3 and NRC Regulatory Guide 1.108 and submitted a special report (dated July 28, 1994) to the NRC as required by plant technical specifications. The testing frequency of the 3A EDG remained at once per month, and a root cause failure analysis will be performed on the failed speed switch.

Additionally, the licensee performed a macroscopic review of previous EDG problems in order to determine any generic implications, recurring type problems, or failure patterns. This review was performed under the auspices of the EDG reliability

program, instruction TDI-TECH-006, as well as a request by the plant manager. This engineering review included EDG problems since the dual unit outage. The report concluded that the failures were not related and that no further action was necessary.

The inspectors discussed the event with the system engineer and the component specialist, reviewed the condition report and control room logs, and reviewed the special report and the report issued by engineering. The inspectors concluded that the licensee aggressively responded to the DC ground which resulted in the identification of the speed switch problem. Additionally, the inspectors noted a strength in that the EDG reliability program requires a macroscopic review of all recent EDG problems. The inspectors intend to monitor EDG related issues in future inspections.

6.2.3 Process Radiation Monitoring System

The inspectors reviewed the licensee's program for process radiation monitors of plant effluents. This included the following monitors:

Monitor No.	Effluent
R-11	containment particulate (both units)
R-12	containment noble gas (both units)
R-14	plant vent (common)
R-15	SJAE (both units)
R-17A and B	CCW (both units)
R-18	liquid release (common)
R-19	steam generator blowdown(both units)
R-20	CVCS letdown (both units)
RAD-6426	MSL (DAM-1) Monitor (common)
RAD-6304	plant vent SPING (common)
RAD-6418	spent fuel pool SPING (Unit 3 only)
RAD-6417	air ejector SPING (both units)
RAD-6311A and B	containment high range (both units)
RAD-6642 and 6643	control room ventilation (common)

The inspectors walked down portions of this system with the technical department system engineer. Items examined in the field included material condition, labelling, monitor and electronics status, operability, local and remote readouts, and actuation functions (trips and/or isolations). The inspectors noted that the system engineer was very knowledgeable regarding this system.

The inspectors also reviewed applicable technical specifications including technical specifications 3/4.3.3.1, Radiation Monitors for Plant Operations; technical specification 3/4.3.3.3, Accident Monitoring Instrumentation; technical specification 3/4.3.3.5, Radioactive Liquid Effluent Monitoring Instrumentation; and technical specification 3/4.3.3.6, Radioactive Gaseous Effluent Monitoring Instrumentation. The inspectors checked for monitor operability action statements and surveillance requirements. Selected calibration procedures (PMIs) were also reviewed.

The inspectors noted that each radiation monitor had associated setpoints (high alarm, trip, and alert). The control room electronic drawers had calibration stickers which were not at times consistent with calibration information provided by chemistry and I&C. Further, the R-11 and R-12 monitors had unofficial calibration stickers which were crossed out multiple times. The inspectors verified that the process radiation monitors were appropriately calibrated. The inspectors discussed this issue with operations, I&C, and chemistry. The licensee committed to improving the documentation for process radiation monitoring instrument setpoints in the ODCM and in documents 5610, 5613, 5614-M-313; and to removing the inappropriate calibration sticker information. The inspectors intend to review these corrective actions in a future inspection. The inspectors concluded that the licensee appropriately responded to these concerns.

The inspectors also reviewed operations-related procedures (ARPs, EOPs, and ONOPs) and interviewed selected operators to ensure that effluent releases would be appropriately responded to by the control room. The inspector concluded that operators were knowledgeable, and that procedures were appropriate.

6.2.4 Nuclear Instrumentation Calibration

The licensee discovered that a possibility existed for introducing errors into the NI power range high power reactor trip setpoint such that actual power would be well above indicated power. A reactor protection system trip is based on indicated NI power. Thus, the error could result in the design basis limits to be exceeded following a credible accident. As a result of this, an operability assessment was performed and measures were put in place to preclude those errors form being introduced into the NI system.

The discovery was made during a review of a 10 CFR Part 21 notification from ABB Combustion Engineering received by FPL's St. Lucie Unit 2 plant. The notification identified the potential for introduction of errors into the NI system due to required adjustments based on secondary calorimetric measurement at low power levels. The licensee determined that the condition was also applicable to Turkey Point.

Turkey Point technical specifications require daily calorimetric power comparisons with the NI at power levels above 15% rated thermal power. If during this comparison, indicated NI power differs from calorimetric power by more than 2%, then technical specifications require that the NI be adjusted to within 2% of the calorimetric. Calorimetrics are performed based on secondary parameters including feedwater flow. At power below 90%, a potential exists for significant errors in feedwater flow measurements due to differential pressure uncertanties at low flow conditions. This could result in an erroneous calorimetric. An error would then be introduced into the NIs upon "gain" adjustment to match the erroneous calorimetric. This error has a magnifying effect at high power levels as the slope of the NI response to neutron flux leakage is linear. If the gain is adjusted to reduce indicated NI power while at low power, the indicated power would be well below actual power following a potential power excursion accident. With the NI high power reactor trip based on indicated NI power, actual power could be well above design limits before initiation of the high power reactor trip.

To preclude introduction of errors into the NI system, a night order was issued which placed administrative controls on NI adjustments based on calorimetrics while at low power. The controls included placing limits on the amount of gain adjustments made at low power to match a lower calorimetric power. In addition, the licensee is developing a permanent solution to prevent introduction to the potential errors discussed above. Westinghouse plans to issue a technical bulletin relative to this issue.

The inspectors reviewed the instructions in the night order and the safety evaluation that was the basis for the administrative controls and determined them to be adequate. It should be noted that following discovery of this issue, a calorimetric had been performed on Unit 3 while at 40% power. The calorimetric and the NI were in agreement during this time and NI adjustment was not necessary.

The inspectors concluded that the licensee was aggressive in pursuing and conservative in addressing this OEF issue.

6.2.5 Ultimate Heat Sink

The inspectors evaluated the performance of the CCW heat exchangers and the ultimate heat sink which included the closed cooling canals, the intake structure, ICW system, CCW system, and RHR heat exchangers. The inspectors reviewed the licensee's daily graphs of ICW temperature limits (based on CCW heat exchanger performance); reviewed the licensee's related technical specifications, UFSAR, DBDs, procedures, and engineering evaluations; and discussed those items with operators and engineers. The technical specifications required the following to be operable for each unit: two (of three installed 50% capacity each) CCW heat exchangers, three (of three installed 100% capacity each) CCW pumps, three (of three installed 100% capacity each) ICW pumps, two (of two installed 100% capacity each) ICW headers, and a UHS (cooling canal system shared among the two nuclear units and the two fossil units) with water temperature to the ICW system of 100°F or less. Technical specifications also required that the CCW system be demonstrated operable at least once per twelve hours by verifying that two heat exchangers and one pump are capable of removing design basis heat loads.

In the daily graphs of ICW temperature limits, the STA plotted the intake temperature every four hours and also plotted the maximum intake temperature for which each pair of the three CCW heat exchangers (for each unit) could remove the design basis accident heat load. The latter plots were based upon periodic tests of CCW heat exchanger heat transfer performance and a constant tube fouling factor which reduced the maximum ICW intake temperature for which the CCW heat exchangers could remove the design basis accident heat load by about 1°F per day.

The licensee's program included cleaning a heat exchanger using mechanical cleaning methods whenever its heat removal ability (maximum ICW intake temperature for which it could remove 50% of the design basis accident heat load) decreased to within 3°F of the actual intake temperature. While the technical specifications required two operable CCW heat exchangers on each unit, the licensee normally operated each unit with all three in service except when one was taken out of service for cleaning or other maintenance. In addition, with one CCW heat exchanger out of service, the licensee followed a 72-hour limit which was administratively controlled. A CCW heat exchanger could be cleaned in less than one day. During the hottest summer periods, the licensee had to clean a CCW heat exchanger on each unit almost daily. The intake temperature would typically vary by several degrees during the day, being the warmest during late afternoon due to solar heating of the shallow water in the UHS closed cooling canal system. The inspector noted intake temperatures as high as about 91°F, and the licensee stated that intake temperatures had changed by as much as about 10°F during a day and had been as high as about 96°F a few years ago.

The inspectors noted on the daily graphs that after cleaning and testing, the Unit 3 CCW heat exchangers were determined to be operable with a maximum ICW intake temperature of about 98°F. Since that 98°F maximum intake temperature for CCW heat exchanger operability then decreased by about 1°F per day due to fouling, it appeared to be potentially inconsistent with the technical specification limit of 100°F for the UHS. The inspectors asked to see the licensee's engineering evaluation that supported the technical specification number of 100°F for the UHS intake temperature and found that the licensee did not have such a written engineering evaluation. The engineering manager stated that the licensee would generate an engineering evaluation to support the 100°F technical specification requirement for the UHS, revise the site DBDs to clarify the relationship between the UHS technical specification limiting temperature and the CCW heat exchanger surveillance curves, and revise the bases for Technical Specification 3/4.7.4 to tie UHS limiting temperature to CCW heat exchanger operability surveillance curves.

Licensee design and system engineers for the CCW and ICW systems described fouling mechanisms, fouling rates, and the results of various methods of cleaning for the CCW heat exchanger tubes. They stated that with good mechanical cleaning, the CCW heat exchangers had been demonstrated operable in the past with a maximum intake water temperature of well over 100°F. However, since good cleaning may cause faster wear of the tubes, the maintenance department did not routinely do a good cleaning when it was not needed. The inspectors reviewed records of CCW heat exchanger performance tests for the past year and found that on more than one occasion, each heat exchanger had been determined to be operable for maximum intake temperatures over 100°F.

The inspectors concluded that the licensee had a sound and conservative program for monitoring and maintaining CCW heat exchanger operability. The licensee's implementation of the technical specification-required 12-hour surveillance monitoring of CCW heat exchanger performance capability was effective and was generally more limiting to plant operation than the technical specification limit on UHS intake temperature of 100°F. In addition, the licensee's practice of normally operating three CCW heat exchangers (while the technical specification required two) was conservative. The inspectors also concluded that the lack of a written engineering evaluation to support the technical specification limit of 100°F for UHS intake temperature was not a safety concern but was a minor deficiency in the licensee's engineering documentation. The inspectors plan to follow up on the licensee's corrective actions for this deficiency.

Turkey Point utilizes an extensive cooling canal system for its UHS. This system was constructed approximately 20 years ago as a result of a U. S. District Court final judgement dated September

10, 1971. This judgement required a closed-loop cooling system because the EPA stated that warm discharge water from the plant would damage Biscayne Bay and Card Sound if once-through cooling was used.

Unlike typical cooling ponds which are elevated with surrounding dikes and contain fresh water, the Turkey Point cooling system is located at sea level and contains salt water because the underlying rock was too porous for an elevated design. This system is made up of a series of shallow parallel canals in an area approximately five miles long and two miles wide. The cooling water surface area of this system is about 4,000 acres, and the berm land surface area is about 1,700 acres. It takes approximately 52 hours for water leaving the plant discharge structure to traverse this 168 mile long system and return to plant intake structure.

This canal system also serves as the habitat for approximately 35 adult and juvenile american crocodiles (an endangered species) and 12 resting sites have been cited in the canal system this year. As of July 27, 1994, the licensee's land utilization group had captured, tagged, and released 142 baby crocodiles from some of these resting cites, and more are expected to hatch. Last year, 190 were captured, tagged, and released.

Waste heat from the plant is transferred from the cooling system to the atmosphere by two modes. Radiation to the atmosphere accounts for approximately 60% of the total heat transfer. This is effective only when the water surface has a clear view overhead. Both evaporation and convection together account for the remaining 40%. These occur as a function of air velocity near the surface of the water.

During the first ten years of operation, the maintenance program was rather minimal; and as a result, the cooling system had deteriorated significantly. There was heavy tree and brush growth on the berms and substantial weed growth in the canals. As a result of the original construction, one foot or more of silt was left on the bottom of all of the canals. This caused no problem in the four deeper canals, (typically twenty feet deep for the discharges, collection, and return of the water) but the combination of silt and weeds in the shallow canals (typically two to three feet deep) caused severe flow blockage in many canals.

During the early 1980s, the licensee began a concentrated effort to select construction techniques and amphibious equipment that could effectively work in the cooling system to do the needed jobs. After the performance of a demonstration dredge test program, purchase of initial equipment, and use of this equipment for a few years; the licensee instituted a five-year major maintenance program in January 1988 to halt system deterioration and improve efficiency. The physical improvements as a result of

this program were outstanding and resulted in a condition that was far superior to the cooling canal system's original condition in 1973. This effort also resulted in a significant increase in the thermal and hydraulic performance capability of the system.

Following the completion of the five-year major maintenance program, the licensee instituted a less intense, long-term maintenance and enhancement program in 1993. The new program was designed to maintain the system in its present good condition and to increase the water surface area by 1% per year by controlling underwater growth in the canals, keeping the berm land areas cleared, and widening the canal edges on a periodic basis to add water surface area and reduce erosion. The annual addition of 1% of new water surface area over a 10-year period will increase the total size by 400 acres and will reduce the plant intake water temperature 0.61°F. The licensee considered this to be a significant improvement. Without this maintenance, the system would begin to deteriorate; and over a 10-year period, the effective cooling surface would decrease by 20% (800 acres) from its present size as experienced during the 1970s.

The annual canal maintenance included the following activities:

- development, construction, and operation of an underwater weed clearing machine followed by the clearing of weeds in 20 to 25 miles of canals each year after selecting the canals that most urgently need weed removal treatment,

- continuous collection and removal of floating loose weeds and algae using floating booms in two key locations to minimize loose weed entry into the plant intake structures, and

- adjustment and construction of new throttling dikes in the canals with amphibious backhoes as needed to achieve uniform water flow in the parallel canals.

The annual berm maintenance included the following activities:

- cultivation of the berms as needed with a tractor-type berm mower or burning to keep down all trees and large bushes,

- application of herbicide spot treatment on berm edges and other trouble spots,

- trimming 15% (approximately 45 miles) of the berm edges per year with amphibious backhoes to make the edges more stable against erosion and to increase the depth of the canal along the berm edge and spreading the salt water soaked trimmed material on top of the berm to consolidate the berm surface and retard future plant growth, and

- re-levelling of the dikes with the berm mower on 33% (approximately 12 miles) of the berms each year until all are levelled.

The licensee purchased the amphibious backhoes in May 1993 and the berm mower in November 1993. The weed clearing machine was developed, constructed, and then became operational in February 1994. The licensee is also currently utilizing one of the two dredges which were operational during the performance of the five-year major maintenance program. One dredge was sold after completion of the program, and the licensee plans to sell the other dredge.

The inspectors toured the cooling canal system with the land utilization site superintendent and observed ongoing canal and berm maintenance. The inspectors also reviewed the systems' history and design features and the licensee's maintenance and improvement program. The inspectors concluded that the licensee's land utilization group has been pro-active in maintaining and improving the performance of this cooling canal system and the UHS. Further, the cooling canal system was operating as designed and met the UHS requirements.

6.2.6 Monthly Operating Reports

The inspectors reviewed the June 1994 Monthly Operating Report and determined it to be complete and accurate.

7.0 Plant Support (71750 and 92904)

7.1 Inspection Scope

The inspectors verified the licensee's appropriate implementation of the physical security plan; radiological controls; the fire protection program; the fitness-for-duty program; the chemistry program; emergency preparedness; plant housekeeping/cleanliness conditions; and the radiological effluent, waste treatment, and environmental monitoring programs.

The inspectors reviewed previous open items to assure that corrective actions were adequately implemented and resulted in conformance with regulatory requirements.

7.2 Inspection Findings

7.2.1 Unescorted Visitors Within the Protected Area

On July 15, 1994, a security guard noted two unescorted individuals wearing visitor badges in the protected area. The incident occurred in the vicinity of the water treatment plant which is located within the protected area. Upon discovery, the security guard immediately notified the CAS and assumed escort

responsibility for the two visitors. Shortly thereafter, the individual who had the escort responsibility returned to the area. The individual with the escort responsibility was a contractor working for the chemistry department. The two visitors had been brought in to assist with the water treatment plant operation.

When asked by the security guard as to why the escort was not with the visitors as required by the escorting procedures, the escort stated that he was involved in a rush job and that he had left the visitors line of sight only for a minute. A conservative decision was made by the security guard to escort the visitors through the completion of their jobs. The licensee concluded that the event was loggable per the security plan.

Another incident where a visitor was outside of the line of sight of his escort had occurred in March 1994 and is discussed in NRC Inspection Report No. 50-250,251/94-07 dated May 12, 1994. This incident was identified by the inspector and had been classified as Non-Cited Violation 50-250,251/94-07-01, Unescorted Visitor Within the Protected Area. As corrective action to the incident that occurred in March, the licensee had disciplined the involved individual and had promulgated the escorting requirements in the weekly site newsletter.

Licensee corrective actions for this recent event included the following:

- implemented a new policy requiring visitors to be signed for by their escorts, including the use of a written visitor/escort transfer form,

- verified that escort responsibilities were addressed in general employee training,

- removed the escorts' access to the site,

- met with the escorts' management, and

- promulgated revised escort responsibilities in the weekly site newsletter and in information bulletin NO. 94-19, emphasizing the legal requirements, and including a written understanding of the policy.

The failure to properly escort visitors within the protected area on July 15, 1994, is a violation of 10 CFR 73.55(d)(6) which requires that individuals not authorized by the licensee to enter protected areas be escorted by a watchman or other individual designated by the licensee while in a protected area. This licensee-identified violation is similar to an NCV issued on May 12, 1994. The inspectors considered this recent example another isolated instance of personnel error made by a different contractor. Corrective actions from the previous event were

evaluated to be adequate. The inspectors concluded that the recent example was not a violation that could have been reasonably prevented by previous corrective actions. Further, licensee corrective actions for this incident appear to be strong. The recent event will be reported to the NRC in the quarterly safeguards event log. Therefore, this recent violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in section VII.B of the NRC Enforcement Policy of 10 CFR Part 2, Appendix C. This item will be tracked as NCV 50-250,251/94-13-02, Unescorted Visitors Within the Protected Area. This item is closed.

7.2.2 (Closed) IFI 50-250,251/92-12-01, Review Scenarios for Practice Exercises with the Graded Exercise for Similarity of Events

This issue was reviewed during the 1993 annual emergency preparedness exercise. (Refer to NRC Inspection Report No. 50-250,251/93-27 for additional information.) The scenario was satisfactory and was not similar to the practice exercises. Further, during the 1994 exercise (Refer to section 7.2.4 of NRC Inspection Report No. 50-250,251/94-11 for additional information.), the inspectors again reviewed this issue and noted that the actual scenario differed from the practice scenarios. Based on the above, the IFI is considered closed.

7.2.3 (Closed) Height Limit for Climbing Without Fall Protection

In section 5.2.3 of NRC Inspection Report No. 50-250,251/94-07, the inspectors found that the lack of a specified height limit for climbing without fall protection was a deficiency in the licensee's safety program. During the current inspection period, the inspectors reviewed licensee Information Bulletin No. 94-16, dated June 13, 1994, which promulgated requirements for the use of fall protection at the Turkey Point plant. The information bulletin included a statement that fall protection must be used when working ten feet or more above the ground where there are not hand rails on all four sides. It also described the proper use of safety belts and full body harnesses. The inspectors concluded that the licensee's information bulletin was well written and adequately addressed the issue. This issue is closed.

8.0 Exit Interview

The inspection scope and findings were summarized during management interviews held throughout the reporting period with both the site vice president and plant general manager and selected members of their staff. An exit meeting was conducted on August 5, 1994. The areas requiring management attention were reviewed. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee. The inspectors had the following findings:

Item Number	Status, Description, and Reference
50-250,251/94-13-01	(Opened) VIO - Missed Valve ISTs (section 5.2.4)
50-250,251/94-13-02	(Closed) NCV - Unescorted Visitors Within the Protected Area (section 7.2.1)

Additionally, the following previous item was discussed:

Item Number	Status, Description, and Reference
50-250,251/92-12-01	(Closed) IFI - Review Scenarios for Practice Exercises With Graded Exercises for Similarity of Events (section 7.2.2)

9.0 Acronyms and Abbreviations

ABB	Combustion Engineering
AC	Alternating Current
ADM	Administrative
ANPS	Assistant Nuclear Plant Supervisor
ARP	Annunciator Response Procedure
ASME	American Society of Mechanical Engineers
CAS	Central Alarm Station
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CNRB	Company Nuclear Review Board
CV	Control Valve
CVCS	Chemical Volume Control System
DBD	Design Basis Documentation
DPR	Docket License Number
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EPA	Environmental Protection Agency
°F	Degrees Fahrenheit
FPL	Florida Power and Light
gpm	Gallons Per Minute
HHSI	High Head Safety Injection
I&C	Instrumentation and Control
ICW	Intake Cooling Water
IFI	Inspector Followup Item
ISI	Inservice Inspection
IST	Inservice Test
LER	Licensee Event Report
LOCA	Loss-of-Coolant Accident
LOOP	Loss of Offsite Power
MCC	Motor Control Center
MOV	Motor-Operated Valve
MSL	Main Steam Line
NCV	Non-Cited Violation
NI	Nuclear Instrument

NOV	Notice of Violation
NPS	Nuclear Plant Supervisor
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
ODCM	Offsite Dose Calculation Manual
OEF	Operating Experience Feedback
ONOP	Off Normal Operating Procedure
OP	Operating Procedure
OSHA	Occupational Health and Safety Administration
OSP	Operations Surveillance Procedure
OTSC	On-the-Spot Change
P21	10 CFR Part 21
PMI	Preventive Maintenance - I&C
PNSC	Plant Nuclear Safety Committee
PTN	Project Turkey Nuclear
QA	Quality Assurance
QC	Quality Control
R/RAD	Radiation Monitors
RCO	Reactor Control Operator
RHR	Residual Heat Removal
rpm	Revolutions Per Minute
RWST	Refueling Water Storage Tank
SFP	Spent Fuel Pit
SJAE	Steam Jet Air Ejector
SMI	Surveillance Maintenance - I&C
SPING	System Particulate, Iodine Nobile Gas (Radiation Monitor)
STA	Shift Technical Advisor
SV	Solenoid-Operated Valve
TDI	Technical Department Instruction
TPCW	Turbine Plant Cooling Water
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
VIO	Violation
WR	Work Request