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

Report Nos.: 50-250/95-15 and 50-251/95-15

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 30 through September 2, 1995

Inspectors: Edwin Lea, for TPJ 9/29/95
T. P. Johnson, Senior Resident Inspector — Date Signed

B. B. Desai, Resident Inspector

Approved by: K. D. Landis 9/29/95
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 engineered safeguards walkdown, operational safety, refueling preparations, 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 inspectors identified the following non-cited violation:

Non-cited violation 50-250,251/95-15-01, Inadequate Procedure Resulting in Both Containment Isolation Portion of Engineered Safeguards Trains Taken Out-of-Service Simultaneously (section 4.2.7).

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During this inspection period, the inspectors had comments in the following functional areas:

Plant Operations

Shift turnovers were conducted professionally and demonstrated complete information exchange. Reactivity parameters were methodically and deliberately controlled during flux mapping (section 3.2.1). Operator response to off-normal conditions such as 3A Reactor Coolant Pump oil level alarm, 4A steam generator level deviation alarm, and control oil leak was noted to be prompt and in accordance with procedures. This demonstrated a strong training program as well as strong teamwork (section 3.2.2). The inspector noted that the licensee reacted appropriately and was responsive to questions pertaining to an indication and a potential clogging problem with a containment isolation valve. The logging of the action statement associated with the containment isolation valve during troubleshooting activities could have been more detailed (section 3.2.3). Portions of the Unit 3 intake cooling water and containment spray systems were walked down and no significant discrepancies were noted (section 3.2.4). The inspector concluded that Unit 3, Cycle 15 refueling outage preparations involved conservatism with an emphasis on outage risk assessment (section 3.2.5).

Maintenance

Inspector observed station maintenance and surveillance testing activities were completed in a satisfactory manner (sections 4.2.1 and 4.2.2). The decision to issue a condition report and evaluate as-found data associated with pressurizer safety valve relief setpoints was appropriate and conservative. Further, the safety evaluation concluded that design basis was not violated due to two of the three safety valves having an as-found lift setpoints beyond that required by current Technical Specifications (sections 4.2.3). The licensee initiated the work control center at Turkey Point with initial positive results (section 4.2.4). Observed auxiliary feedwater related work during this month was conducted appropriately and conservatively (section 4.2.5). A questioning attitude exhibited by the operators led to the identification of a weakness in the calibration process involving non-safety related components that have a potential for affecting safety related parameters (section 4.2.6). The questioning attitude exhibited by the operator as well as the followup performed by the training instructor that led to the identification of a vulnerability associated with disabling both trains of the Containment Isolation portion of Engineered safeguards during testing were exemplary. The testing procedure inadequacy will be classified as a non-cited violation (section 4.2.7). Inspector observed maintenance during freeze seal operations, nuclear instrument repairs, and charging pump activities was appropriately performed (sections 4.2.8 through 10). The issuance of a condition report due to a repetitive problem associated with the containment isolation valve issue discussed in section 3.2.3 could have been more timely (section 3.2.3).

Engineering

Engineering involvement and assessment with regard to the pressurizer safety valve as-found lift setpoint Engineered Safeguards testing were appropriate and timely (sections 4.2.3 and 4.2.7). The engineering analysis associated with four high head safety injection pumps aligned to a single refueling water storage tank which concluded that no concerns existed was appropriate. Further, the discovery of the issue by QA in that the Design Basis Document did not address this issue was a strength (section 5.2.1). The meeting between engineering and the NRC in Region II was a good interchange of information (section 5.2.2). Monthly operating report and the semi-annual fitness-for-duty program report were complete and accurate (section 5.2.3).

Plant Support

The inspectors noted conservatism, strong teamwork, and effective management oversite during preparations for a hurricane. The hurricane did not significantly affect the plant and both units remained at full power through the hurricane watch and warning (section 6.2.1). The inspector noted that response to a non-credible bomb threat and a Fitness-For-Duty issue was appropriate (sections 6.2.2 and 6.2.3). An occupational safety program with strong management commitment was noted (section 6.2.4).

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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
J. C. Balaguero, Technical Department Supervisor
*C. R. Bible, Acting Site Engineering Manager
W. H. Bohlke, Vice President, Engineering and Licensing
M. J. Bowskill, Reactor Engineering Supervisor
J. E. Geiger, Vice President, Nuclear Assurance
J. H. Goldberg, President, Nuclear Division
*R. G. Heisterman, Maintenance Manager
*P. C. Higgins, Outage Manager
G. E. Hollinger, Training Manager
R. J. Hovey, Assistant to the Site Vice-President
*M. P. Huba, Procurement Supervisor
*D. E. Jernigan, Plant General Manager
H. H. Johnson, Operations Manager
M. D. Jurmain, Electrical Maintenance Supervisor
V. A. Kaminskas, Services Manager
T. F. King, Acting Fire Protection/Safety Supervisor
J. E. Knorr, Regulatory Compliance Analyst
T. J. Koschmeder, Acting Instrumentation and Controls Maintenance Supervisor
R. S. Kundalkar, Engineering Manager
J. D. Lindsay, Health Physics Supervisor
*F. E. Marcussen, Security Supervisor
D. D. Miller, Acting Projects Supervisor
H. N. Paduano, Manager, Licensing and Special Projects
*T. F. Plunkett, Site Vice President
R. E. Rose, Nuclear Materials Manager
A. M. Singer, Operations Supervisor
R. N. Steinke, Chemistry Supervisor
*D. J. Tomaszewski, Acting Technical Manager
B. C. Waldrep, Mechanical Maintenance Supervisor
*E. J. Weinkam, Licensing Manager

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

1.2 NRC Resident Inspectors and other NRC personnel on Site

*B. B. Desai, Resident Inspector
*T. P. Johnson, Senior Resident Inspector
R. S. Baldwin, Operator Licensing Examiner

* Attended exit interview (Refer to section 8.0 for additional information.)

Note: An alphabetical tabulation of acronyms used in this report is listed in section 9.0 of this report.

2.0 Plant Status

2.1 Unit 3

Unit 3 operated at or near 100% reactor power for the entire report period and has been on line since April 9, 1995. License preparations for the cycle 15 refueling outage continued.

2.2 Unit 4

At the beginning of this reporting period, Unit 4 was operating at or near 100% reactor power and had been on line since March 12, 1995. Reactor power as well as generated MWe were reduced to approximately 40% to perform Main Turbine valve testing and Turbine Plant Cooling Water heat exchanger cleaning on August 22. 1995. The unit was returned to full power following successful testing and maintenance activities on August 24, 1995.

3.0 Plant Operations (40500, 60705, 71707, and 93702)

3.1 Inspection Scope

The inspectors verified that the licensee operated the facilities safely and in conformance with regulatory requirements. The inspectors 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, inspections of outage preparation activities, and evaluation of the licensee's management control.

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 an inspection designed to verify the status of the Containment Spray and Intake Cooling Water systems. This was accomplished by performing a partial walkdown of accessible equipment. The inspectors reviewed system procedures, housekeeping and cleanliness, major system components, valves, hangers and supports, local and remote instrumentation, and component labelling.

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

3.2 Inspection Findings

3.2.1 Control Room Observations

The inspector routinely attended shift turnover meetings. The inspector noted that these meetings were done in an orderly and concise manner. The crews were attentive and participated freely. In some cases, the control room noise level was higher than expected. Overall, shift turnover was performed without any noted problems. The inspector observed shift turnovers between individual operators. The inspector found these turnovers complete and professionally done.

The inspector observed the preparations for Unit 4 neutron flux mapping. The operators involved methodically and deliberately maintained flux within the required band. Communications between the ANPS and the RCO were concise. A heightened awareness concerning plant parameter changes was evident from the deliberate actions of the RCO during rod movement, borations and dilutions. No discrepancies were noted.

At times, the inspector noted a somewhat inconsistent control of personnel entering the control room controls area (surveillance area and restricted areas). The requirements of procedure 0-ADM-200, Conduct of Operations was apparently inconsistently applied. The inspector discussed this with the licensee.

In conclusion, shift turnover and flux mapping activities were professionally conducted; however, minor deficiencies in control room access and use of the plant paging systems were noted.

3.2.2 Operations Response to Off-Normal Conditions

During the inspection period, the inspectors reviewed operations response to several off-normal operating conditions. These conditions included a RCP oil level alarm, a steam generator level control problem, and a turbine intercept valve closure.

On July 28, 1995, at 12:40 p.m., the 3A RCP oil level alarm annunciated. Operators responded per the guidance of the ARP, the ONOP, and the OP. In addition, maintenance and system engineering personnel were notified. Corrective actions included performing containment inspections (in the vicinity of the RCP and the oil collection tank) with no observed abnormalities, lowering the oil temperature alarm setpoint to 150°F, and continuing the 15 minute surveillance of RCP oil temperatures and vibrations per procedure 3-ONOP-041.1, Reactor Coolant Pump Off-Normal. Further, the licensee has noted an historical oil consumption for this RCP motor and intends to address this during the upcoming refueling outage.

On July 30, 1995, at 9:05 p.m., a level deviation alarm occurred on the 4A steam generator. The Unit 4 RCO responded per the ARP, noted a decreasing level and feedwater flow, took manual control of the feedwater regulating valve, and restored level to normal. The licensee maintained a dedicated RCO to control 4A steam generator level while troubleshooting activities were ongoing.

I&C determined that the level control lead-lag card (LM-478) and associated connector were faulty. Replacement activities were completed, PMT was successful, and the 4A steam generator level control system was returned to automatic on July 31, 1995.

On August 2, 1995, at 10:40 a.m., the Unit 3 RCO observed a small (10 Mwe) decrease in turbine-generator output. A review of the control room indications was performed and the RCO noted that the northeast low pressure turbine intercept valve was midpositioned. Maintenance and system engineering personnel performed inspections and subsequently found a small control oil leak in the guarded oil system piping. The leak was from a temporary repair performed in June 1994 per a TSA (refer to NRC Inspection Report No. 50-250,251/94-11 for additional information). During the condition, operators noted secondary plant perturbations and started a third condensate pump. An unrelated false hotwell level indication also occurred which required action to bypass the hotwell makeup valve and to station a local gauge glass watch. The licensee reduced Unit 3 to 70% power and repaired the leak per the approved TSA guidance and a PWO. The licensee intends to perform permanent repairs during the upcoming refueling outage. The unit was returned to 100% power at 2:00 a.m. on August 3, 1995.

The inspectors reviewed operations response to each of these off-normal conditions, including direct observation, log review, condition report followup, and discussions with the on-shift operations personnel both during and after each condition. The inspectors concluded that operator response in each case was prompt in accordance with procedures, and demonstrated a sound training program and attention to operating information. Further, strong teamwork among the operating crew including the STA, maintenance, system and design engineering, and management oversight was evident.

3.2.3 Containment Isolation Valve SV-4-6385 Problems

On August 3, 1995, during a periodic evolution involving sampling the gas space of the Unit 4 PRT, an automatic containment isolation valve (SV-4-6385) exhibited a problem in that the control room switch showed dual (both open and close) indication. Additionally, chemistry was unable to sample the PRT. SV-4-6385 had experienced similar problems in the past and had been replaced on July 1, 1995. The PRT gas space is analyzed every month by chemistry for an explosive mixture of oxygen and hydrogen. A work order was originated and troubleshooting was initiated. Further, SV-4-6385 was declared inoperable in accordance with Technical Specification 3.6.4.a, Containment Isolation Valves, and a four-hour action statement was entered as the redundant automatic containment isolation valve CV-4-516 remained operable and closed. Subsequently, the four-hour action statement was exited and Technical Specification 3.6.4.c was entered upon closing of the manual isolation valve 4-552 located upstream of SV-4-6385 within the affected penetration.

Troubleshooting identified a blockage upstream of SV-4-6385. The licensee postulated that diaphragm valve 4-517B located upstream of SV-4-6385 may have degraded, resulting in stem separation, thus causing the valve to fail close. The diaphragm was also postulated to have caused the block. The pressure gradient caused by the gas analyzer pump as a result of the block was postulated to have caused the dual indication on SV-4-6385. This 517B valve is located inside containment behind the bio-wall preventing immediate repairs. The licensee plans to conduct repairs during a unit outage.

The inspector discussed the issue with the licensee, including the system engineer. The inspector asked why a condition report had not been issued due to the repetitive problem. The system engineer inquired and determined that a condition report was in the process of being issued. The inspector concluded that the licensee was responsive to inspector questions. The inspector also concluded that the issuance of a condition report could have been more timely. The inspector also noted that the Unit 4 logs did not fully discuss the sequence of events relative to this containment isolation valve issues. The inspector plans to followup on these issues during future inspections.

3.2.4 Safety System Walkdowns

On August 15, 1995, the inspector performed a walkdown of trains A and B of the Containment Spray System for Unit 3. During the walkdown, the inspector noted boric acid crystals on the packing of valves 3-844A and 3-896T. The Unit 3 ANPS was informed and a PWO was initiated. The inspector did not note any other discrepancies.

On August 17, 1995, the inspector performed a partial walkdown of the Unit 3 ICW system. This included the area between the travelling screens and the Circulating Water pumps. The inspector found one discrepancy. The discrepancy was a missing label on strainer YS-3-1402. The licensee was informed of the missing label.

The inspector concluded that for the portion walked down, the safety systems were properly aligned.

3.2.5 Unit 3 Refueling Preparations

Unit 3 is scheduled for a 35-day refueling outage during the period September 4 to October 8, 1995. The inspectors reviewed the licensee's preparation for refueling and outage activities. This included the following activities:

- fuel receipt, inspection, and movement procedures;
- outage schedule, critical path, and goals;
- PC/M scope;

- major maintenance and testing activities;
- plant conditions and mode changes;
- core offload and reload activities;
- operator training relative to shutdown conditions;
- RPV draindown;
- outage risk assessment;
- control of contractors and temporary employees;
- shift director schedules and functions;
- plant manager briefings; and
- licensee commitments and technical specifications.

The inspectors reviewed in detail administrative procedure O-ADM-051, Outage Risk Assessment and Control. This procedure provided recommended equipment to be maintained operable or available during shutdown conditions for decay heat removal, inventory control, power availability, reactivity control, containment integrity control, instrumentation, and fire protection. In addition, the inspectors discussed this process with licensee plant, outage, and engineering management personnel. The licensee also established a risk assessment team and leader whose function was to review schedule, key shutdown functions, and key equipment availability.

The inspectors noted strong management oversight and commitment to safety. A meeting with licensee and NRC representatives was held on August 30, 1995, to discuss the upcoming Unit 3 refueling outage. This discussion was beneficial in understanding critical path, outage schedule, goals, and other information items.

The inspectors observed the new fuel receipt, storage, and transfer process from the new fuel storage room to the spent fuel pool. Personnel from reactor engineering, operations, and HP were involved. The inspectors noted excellent teamwork among the participants including good procedure usage and good communications. The inspectors also verified that the control room was cognizant of all activities.

The inspectors also noted QA/QC involvement in Unit 3 new fuel receipt, inspection, and transfer operations. QA/QC performed monitoring and surveillance activities of the spent fuel pool housekeeping, new fuel shipping containers receipt and inspection, new fuel handling equipment, and new fuel transfer operations. The QA/QC housekeeping inspection noted loose material in the vicinity of the pool. The appropriate personnel were notified, and this material was removed prior to new fuel movements into the spent fuel pool.

The inspectors concluded that the licensee is appropriately prepared for the Unit 3 Cycle 15 refueling outage. The risk assessment process appeared to be effective. The inspectors plan to monitor the Unit 3 refueling outage related activities.

4.0 Maintenance (61726 and 62703)

4.1 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.

4.2 Inspection Findings

4.2.1 Maintenance Activities Witnessed

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

- Unit 4 turbine intercept valve repairs (section 3.2.2),

- AFW planned outage (section 4.2.5),

- Power Range Nuclear Instrumentation Bistable Replacement (Section 4.2.9)

- PASS Freeze Seal (section 4.2.8).
- 0-PMI-47.4, "Chemical Volume and Control System Charging Pump Suction Stabilizer Inspection/Maintenance" performed on 4B charging pump (section 4.2.10).

- 0-PMM-047.6 "Chemical Volume and Control System Charging Pump General Inspection," performed on the "4C" CCP.

For the maintenance activities observed, the inspector determined that those activities were conducted in accordance with approved maintenance procedures and work-orders.

4.2.2 Surveillance Testing Activities Observed

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

- Various diesel testing during hurricane Erin preparations (section 6.2.1),

- Procedure 4-OSP-049.1, Reactor Protection Logic Test,

- Procedure 4-OSP-023.1, EDG Operability Test

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

4.2.3 Pressurizer Safety Valve As-Found Relief Setpoints

The inspector reviewed and discussed with the licensee, condition report No. 95-513, associated with the as-found set pressure testing of the Unit 4 pressurizer safety valves conducted on June 20, 1995. These safety valves were removed from Unit 4 during the cycle 14 refueling outage and were replaced with pretested safety valves. Two of the three safety valves were found to have an as-found lift setpoint beyond the +/- 1% required by Technical Specification 3.4.2.2. The as-found relief setpoints relative to RCS design pressure, (e.g., 2485 psig) for the three valves were as follows:

Valve Serial No:	As-Found Setpoint (psig):
N69877-01-0009	2427 (-2.3%)
H51249-1580	2553 (+2.7%)
N6977-01-0008	2491 (+0.24)

Further, the pressurizer safety valves are used in an installation that is provided with a loop seal configuration. The loop seal has the potential for creating a shift in set pressure of up to +1 % in accordance with Westinghouse Owners Group Project MUHP2351, Pressurizer Safety Valve Set Pressure Shift. Thus, valve H51249-1580 had the potential for relieving non-conservatively at approximately 2578 psig (+3.7% of design pressure) during transient conditions.

The pressurizer safety valves were also subjected to the testing requirements of Article IWV-1000 of the ASME Code Section XI, 1989 edition. Per this subsection of the ASME Code and its reference to ASME/ANSI OM Part 10, the safety valve set pressure tests were required to meet the acceptance criteria of paragraph 1.3.3.1 of ASME/ANSI OM Part 1. This paragraph indicates that for valves which fail to meet the set pressure acceptance criteria, the causal effect shall be evaluated for determination of the need for additional tests. No repair or replacement was specified for these test failures unless the set pressure stamped on the valve is exceeded by 3% or greater. ASME Code Section III, paragraphs NB-7310 and NB-7410 required that when more than one pressure relieving device is used for overpressure protection, the set pressure, of at least one of the pressure relief devices, shall not be greater than the design pressure of any component within the pressure retaining boundary of the protected system. Further, the additional pressure relief devices may have higher settings, but in no case shall these settings be such that the total accumulated pressure exceeds 110% of the design pressure at total rated relieving capacity.

As noted above, none of the three safety valves had as-found set pressure outside the 3% maximum allowable set pressure tolerance

as specified by ASME Code Section XI. However, when the loop seal configuration was taken into account, one of the safety valves had the potential for relieving at 3.7% of its lift pressure.

Consequently, an engineering evaluation was performed which concluded that there was no current operability concern as Unit 4 had pretested valves installed. Further, the as-found set pressure of 2427 psig for valve N69877-01-0009 was below design pressure of 2485 psig. Based on the safety valve design of going into full lift right at set pressure (no accumulation), the licensee determined that this allowed the other two safety valves to relieve at a pressure higher that the RCS design pressure. Thus, the total accumulated pressure would not exceed the Technical Specification 2.2 safety limit of 2735 psig, i.e., 110% of the design pressure at the total rated relieving capacity.

The evaluation also concluded that the deviation between the as-found and specified set pressure on these valves was within the ASME Code Section III acceptance criteria for system designs that uses more than one safety valve and that there was no adverse impact on the capability of these valves to perform their code safety function of preventing over-pressurization of the RCS. Additionally, the recorded deviation in the set pressures would not have resulted in any detrimental impact on the Unit 4 safety limits at any time during the occurrence of any of the analyzed Chapter UFSAR 14 events.

The licensee plans to however correct the discrepancy prior to reuse of these valves. Further, the licensee plans to request an amendment to current Technical Specification such that the safety valve set point, including main steam safeties, would match the requirement of ASME Code Section XI.

Notwithstanding, the inspector questioned the licensee if requirements of current Technical Specification 3.4.2.2 were met as a result of two of the primary safety valve's as-found lift set point exceeding 1%. Licensee considers that the safety valves were tested operable when installed. Further, there was no way of identifying drift in relief set point during the cycle. In the interest of consistency, as this issue had come up at other sites, the inspector requested NRR to review the licensee's evaluation, including their operability and reportability determinations.

The inspector concluded that licensee decision to issue a condition report and evaluate the as-found data was appropriate and conservative. Further, the inspectors noted that the licensee has plans to submit a Technical Specification change in the near future.

4.2.4 Work Control Center

The licensee recently instituted a work control center (WCC) process and capability at Turkey Point. The WCC functions as the operations department primary interface with the maintenance department for approving PWOs, issuing clearances, and entering equipment into the OOS logs. A designated ANPS and RCO provide these functions, maintaining a close communication with the control room ANPSs. The WCC is physically located on the turbine deck 58 foot level, where the non-licensed operator break room was previously located. The licensee intends to man the WCC during weekday day-shifts and continually during outages. Procedure ODI-CO-019, Work Control Center provides guidance on WCC operation, manning, and functions.

The inspector reviewed the ODI-CO and observed the WCC operation during the period. The inspector noted that an immediate effect was eliminating extraneous control room traffic and noise. The WCC ANPS maintained close communication with the control room ANPSs. On several occasions, the inspector noted that only one ANPS was in the control room as the second ANPS on-shift was designated as the WCC ANPS. Although allowed by technical specifications and licensee ADM requirements, this removed one of the unit designated ANPSs from the control room oversight functions. The inspector discussed this practice with operations and plant management. The licensee agreed that this practice was not preferred, and stated that they would attempt to schedule an extra ANPS to man the WCC. Thus, two ANPSs would be provided for unit oversight in the control room.

The inspector concluded that the licensee's WCC process and implementation was appropriate. The inspector intends to continue to monitor WCC performance.

4.2.5 Auxiliary Feedwater Outage

At about 9:00 p.m., on August 6, 1995, operators removed the A AFW pump from service for planned corrective and preventive maintenance. This removed Unit 3 and 4 train 1 AFW, and placed both units in a 72-hour LCO per Technical Specification 3.7.1.2(1). This scheduled maintenance was in accordance with the licensee's plan. Maintenance activities included valve repacking, leak repairs, inspections, relief valve replacements, electrical work per these PC/Ms, and periodic testing. After a common valve was repacked, during peak-shift on August 7, 1995, the licensee realigned the C AFW pump to train 1 for both units, thus relaxing the 72-hour LCO to a 30-day LCO per Technical Specification 3.7.1.2(3).

During testing of the A AFW pump, the licensee experienced a problem resetting the mechanical overspeed tappet following a successful mechanical overspeed trip. An investigation revealed that the polyurethane tappet head had stuck in the tappet head guide. The licensee contacted the manufacturer and was informed that due to similar problems at other sites related to environmentally initiated polyurethane head growth, the tappet design had been changed in 1990. The new tappet head design included a metallic guided surface with greater clearance between he molded head and guide. Further, the manufacturer had relayed the information in a letter dated June 22, 1990. The replacement

tappet obtained from stock was of the new design. The tappet was replaced and the reset mechanism was successfully tested.

The inspector observed a significant portion of the maintenance and testing. The inspector also reviewed the new tappet design as well as the letter that informed users of the new design. The inspector confirmed that the mechanical overspeed function was not compromised under the old as well as the new tappet design. Further, the inspector verified that the manufacturer had not deemed the tappet replacement urgent but recommended that it be replaced when plant operating schedule permits. Turkey Point plans to review and replace the tappets for the B and C AFW pumps at the next available operating opportunity.

Subsequently, the A AFW pump was satisfactorily tested and returned to service, and the C AFW pump was re-aligned to train 2 and satisfactorily tested on August 10, 1995. These actions applied to both units.

The inspectors reviewed the licensee's work scope, plan, and schedule and PSA reviews. Overall risk was minimized by around-the-clock work activities and by AFW realignment activities. The inspectors observed various maintenance and testing activities, verified Technical Specification compliance, and checked the clearances and re-alignment procedures. The inspectors concluded that the licensee acted appropriately and conservatively during the A AFW pump outage.

4.2.6 Calorimetric Instrumentation Calibration

The inspector reviewed and discussed with the licensee an issue associated with main feedwater flow transmitter miscalibration that occurred during performance of 3-PMI-074.19, Calorimetric Instrumentation Calibration. Main feedwater flow transmitters FT-3-476X, FT-3-486-X, and FT-3-496X are calibrated every six months and provide input to the DDPS system to perform secondary calorimetric. Calculated reactor power from a secondary calorimetric is then used to adjust the power range NI currents.

During a routine calibration by I&C on August 9, 1995, FT-3-476X and FT-3-496X were found indicating approximately 4% high. The calibration was completed and FT-3-476X and FT-3-496X were adjusted down by approximately 4%. During peak shift, a secondary calorimetric was performed by operations on Unit 3. The results from this calorimetric were noted by the operators to be questionable. Further, FT-3-476X and FT-3-496X were noted to be reading low on DDPS. Consequently, the three FTs were recalibrated using different M&TE than used during day-shift. FT-3-476X and FT-3-496X were found out-of-specification by approximately the same amount as they were adjusted on day shift, i.e. 4%. These two FTs were then adjusted up 4%. The FTs were then compared to the corresponding Barton flow indicators FI-3-477, FI-3-487, and FI-3-497 for each feedwater loop and found to be in agreement. Consequently, the M&TE used during day shift calibration of FTs was put on hold. This M&TE was later checked on August 10, 1995 with satisfactory results.

Condition report No. 95-605, was originated as a result of the miscalibration. The condition report determined that several weaknesses existed in the calibration process. These included:

- no PMT required following calibration,

- inappropriate cross check performed in that a diverse indication such as the Barton loop flow instruments were not utilized to perform the cross check, and

- it was not communicated to the control room that two flow transmitters had been adjusted.

The licensee initiated corrective actions to address the above issues. Further, the licensee plans to review other PMI's to determine if similar problems exist where a non-safety related instrument important to reactor power or Technical Specifications adjusted without proper review and notifications.

The inspector reviewed the condition report and discussed the issue with the licensee. The inspectors concluded that the questioning attitude of the operators led to the identification of a weakness in the calibration process involving non-safety related components that have a potential for affecting safety related parameters. The inspector also requested that the I&C Supervisor review completed PMI-074.19 to determine if a similar adjustment was made, and especially if the NIs were adjusted based to the new readings. The I&C Supervisor informed the inspector that no similar adjustments were identified.

4.2.7 Both Trains of Containment Isolation Portion of Safeguards Disabled During Monthly Testing

On August 18, 1995, operations identified a concern regarding monthly test procedure OP 4004.4, Containment Isolation Racks QR 50 and QR 51 Periodic Test. It was later confirmed that during the performance of steps 5.a, 6.a, 7.a, 8.a, 9.a, and 10.a of OP 4004.4, the two redundant trains of Containment Isolation portion of ESF are simultaneously taken out-of-service for periods not exceeding a few seconds. This condition was identified by a training instructor following some questions raised by an SRO during a trainee walkdown. Condition report, No. 95-627 was initiated upon identification. Any future performance of OP 4004.4 was put on hold pending resolution of this issue. OP 4004.4 is performed on a monthly basis to meet the surveillance requirements of Technical Specification Table 4.3.2.

Rack QR 50 contains circuitry associated with Train A portion of ESF and rack QR 51 contains circuitry associated with Train B portion of ESF. Actuation for 2 out-of-3 high containment pressure switches (setpoint 4 psig containment pressure) initiates SI through redundant Trains A and B. Similarly, actuation of 2-

out-of-3 high containment pressure switches and 2-out-of-3 high-high containment pressure switches (setpoint 20 psig containment pressure) initiates Containment Spray, Main Steam Isolation, and a Phase B Containment Isolation.

During performance of steps 5.a, 6.a, 7.a, 8.a, 9.a, and 10.a of OP-4004.4, two operators are required to simultaneously depress two test pushbuttons associated with each of the six pressure channels (three high containment pressure and three high-high containment pressure). For each channel, one test pushbutton is located in rack QR 50 and the other test pushbutton is located in rack QR 51. Depressing the test pushbutton associated with rack QR 50 completely disables train A portion of containment pressure related ESF actuations by preventing a train actuating relay from energizing. Similarly, depressing the test pushbutton associated with rack QR 51 completely disables train B portion of containment pressure related ESF functions. Except for the time when both test pushbuttons are depressed simultaneously, each train is tested separately with the other train remaining operable during the test.

The procedural steps requiring depressing both test pushbuttons simultaneously manifested due to a design weakness. This weakness involved a single local confirmation light associated with both train's pressure channels. The test procedure relied on the local light indication to confirm functionality of channel relays being tested. The functionality of the channel relays can also be verified through redundant indications available in the control room.

The licensee performed a past operability evaluation associated with this problem. This evaluation concluded that design basis functions for all plant conditions were met while both Containment Isolation ESF trains were taken out-of-service. UFSAR chapter 14 safety analysis credits operation of the high containment pressure channels only in initiating containment spray during certain design basis events. UFSAR chapter 14 does not take credit for containment pressure logic train initiated SI, Main Steam Line Isolation, and Phase B Containment Isolation. A LOCA was determined to be the most limiting scenario requiring containment spray initiation. For this scenario, the licensee determined that the two containment pressure logic trains would be returned to the normal configuration within a time period which would allow containment spray loading by the emergency load sequencer. This determination was predicated on the fact that during the performance of procedure OP 4004.4, the two test pushbuttons are simultaneously depressed only momentarily and no longer than 13 seconds at a time. If a LOCA and a subsequent high or high-high containment pressure condition occurs during the steps that disables both trains, as soon as the test pushbuttons are released the containment pressure channels would return to the normal configuration, including protection for single failure. Further, the licensee concluded that if procedure OP 4004.4 were being performed and a LOCA occurred during steps other than 5.a, 6.a, 7.a, 8.a, 9.a, or 10.a, it would be highly unlikely that the steps

of the procedure which requires simultaneously depressing both pushbuttons, would commence after initiation of a LOCA.

Nevertheless, several corrective actions were completed or are planned, to address the issue. These include:

- a condition report was initiated,
- performance of procedure OP-4004.4 was administratively put on hold, pending resolution,
- procedure OP 4004.4 was revised to preclude disabling both trains of containment isolation simultaneously by deleting steps 5.a, 6.a, 7.a, 8.a, 9.a, and 10.a,
- an analysis was performed that concluded that plant design basis was not compromised,
- an analysis will be performed to determine if the high containment channel test circuits could be modified or deleted such that both trains are not disabled during testing
- Engineering will review other Technical Specification related instrument test circuits and related procedures to ensure that similar conditions do not exist, and
- an LER pursuant to 10 CFR 50.73 is planned in the near future.

The inspector reviewed and discussed the issue with the licensee and independent verified assumptions of UFSAR Chapter 14, Accident Analysis. The inspector also asked the licensee if there were any single failure vulnerabilities associated with the Containment Isolation circuitry. The inspector was told that though the engineering analysis did not address this issue, engineering had discussed and concluded that single failure vulnerability did not exist as a result of the single light indication in the circuitry.

The inspector concluded that the questioning attitude exhibited by the operator as well as the followup performed by the training instructor that led to the identification of this vulnerability were exemplary. However, the procedural weakness that allowed both trains of Containment Isolation to be simultaneously taken out-of-service during monthly logic testing is considered a violation. However, this procedural violation will not be subject to enforcement action because the licensee identified the issue and because licensee corrective actions were prompt and appropriate. This meets the criteria specified in Section VII.B of the NRC Enforcement Policy. This item is being tracked as NCV 50-250,251/95-15-01, Inadequate Procedure Resulting in Both Trains of Containment Isolation Portion of Engineered Safeguards Being Taken Out-Of-Service Simultaneously. This item is closed.

4.2.8 PASS Freeze Seal

The inspector reviewed a work package for freeze sealing the CCW piping to and from the PASS. Work package JPN-PTN-SEMS-95-038 was reviewed in its entirety. This work package incorporated the use of a freeze seal, PCM-95-054 (modification of U-3 chill water system), with the use of ADM-217, Conduct of Infrequently Performed Tests or Evolutions. The work package appeared to contain all necessary information concerning the use of the freeze seal. The package also contained information concerning contingency actions necessary for the operator implementation provided failure of the freeze seal. There were no discrepancies noted.

The inspector reviewed the work area during the formation of the freeze seal. The inspector noted that the freeze seal took longer to establish than stated in the work package. The work package stated that the entire job would take one shift to accomplish. The inspector determined from discussions with the freeze seal technicians that the final freeze seal took approximately 17 hours to establish. Once the freeze seal was in place the addition of the cross connect piping between Unit 4 and Unit 3 to the PASS system was completed rapidly. The inspector noted that there were a number of reasons why the freeze seal took so long to establish including high ambient room temperature, close proximity of Steam Generator blow down piping, and CCW piping made of carbon steel (required a jacket to be built vice direct nitrogen impingement).

The inspector concluded that the freeze seal work was appropriately performed.

4.2.9 Power Range NI Bistable Replacement

On August 16 the inspector observed I&C technicians replace the N-42 Power Range Nuclear Instrument Overpower Rod Stop Bistable. The work was performed under PWO No. 95022445. The inspector reviewed this work package and did not find any discrepancies. The evolution was performed properly by procedure in the presence of an I&C field supervisor.

The inspector observed operations personnel perform procedure 3-OSP-59.4, Section 7.4, Power Range Instrument Channel Operational Test. This surveillance is performed on a monthly basis. The inspector observed satisfactory completion of the monthly N-42 Channel Operational Test. No discrepancies were noted.

4.2.10 Charging Pump Maintenance

The inspector observed I&C technicians measure the suction bladder pressure of the 4B charging pump During the performance of this evolution an out of specification low value for the suction bladder pressure was measured. This out-of-specification reading required I&C personnel to fill the suction bladder with nitrogen.

The evolution was performed properly by procedure in the presence of an I&C field supervisor. There were no discrepancies noted.

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.

5.0 Engineering (37551, 90712, 90713, 92700, and 92903)

5.1 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.

The inspectors also reviewed the reports discussed below. The inspectors verified that reporting requirements had been met, root cause analysis was performed, corrective actions appeared appropriate, and generic applicability had been considered. When applicable, the criteria of 10 CFR Part 2, Appendix C, were applied.

5.2 Inspection Findings

5.2.1 Design Bases Documentation Issues

The inspector reviewed condition report, 95-593, associated with ESF system configuration for the operating unit while the other unit is in a refueling outage. During this time, four HHSI pumps, two RHR pumps, and two CS pumps are aligned to the operating unit's RWST to ensure an available suction source. The condition report was initiated by QA following a routine audit since this configuration involving four HHSI pumps drawing from a single RWST was not discussed in the design basis document or the UFSAR. Current design calculations for available NPSH to the ESF pumps assume a worst case situation where only two HHSI pumps, two RHR pumps, and two CS pumps are aligned to the operating unit's RWST. Further, the calculations to determine time to switch-over to the recirculation sump following a design bases accident also use the same assumptions.

Turkey Point Units 3 and 4 share four HHSI pumps. Technical Specification 3.5.2 requires the operating unit to have a minimum of three HHSI pumps operable when the shutdown unit is in modes 4, 5, or 6. The shutdown unit utilizes its RWST inventory to fill the refueling cavity to accommodate fuel movement, thereby creating the need to align all HHSI pumps to the operating unit's RWST.

The licensee completed an interim disposition of the condition report and concluded that no operability concerns existed. This operability assessment was based on current mode 1 status of both units. Additionally, for the situation where all four HHSI pumps are aligned to a single RWST, the licensee determined that emergency operating procedures 3 or 4 EOP-E-0, Reactor Trip or Safety Injection, step 17, requires securing HHSI pumps such that only two pumps are injecting. This step occurs relatively early following any safeguards actuation and serves to minimize the time that four pumps draw from a single RWST. The licensee also determined that the HHSI pump represent a relatively small demand of 700 gpm and the effects on time to cold leg recirculation switch-over would be minimal. Further, the licensee requested Westinghouse to perform a review of previous calculations and evaluations, and provide an assessment of the subject configuration including available NPSH to the safeguard pumps.

Westinghouse performed a calculation and concluded that four HHSI pump operations from one RWST was not limiting and that current operational procedures are acceptable. This was based on the assumption that two of the four HHSI pumps are secured from operation within a previously analyzed switchover to containment pump recirculation time as directed by the EOP. Further, the evaluation concluded that the HHSI and CS pumps would be supplied with sufficient NPSH, the RWST low-alarm setpoint remained valid, the RWST draindown during the initial phase remains unchanged, and the RWST vent would not be significantly challenged by the increase in out flow. Upon the inspectors request, the licensee successfully demonstrated, on the simulator, the validity of assumptions involving EOP related operator actions assumed in the Westinghouse analysis.

Based on the Westinghouse analysis, the licensee closed the condition report. However, the licensee plans to incorporate a brief discussion of the subject and the potential effect of continuing to run four HHSI pumps drawing from a single RWST in the Design Basis Documents as well as the basis document for procedures 3 and 4 EOP-E-0, Reactor Trip or Safety Injection.

The inspector reviewed the condition report and discussed the issue with the licensee. The inspector concluded that while the issue should have been discussed initially in the Design Basis Document, upon identification, the licensee conservatively dispositioned it. Further, the identification of the issue by QA during a routine audit was also considered a strength.

5.2.2 Engineering Meeting

The inspector attended a meeting held in the NRC Regional II Office in Atlanta, Georgia between representatives of FPL and the NRC. The licensee presented topics including site engineering, special projects, metallurgical laboratory, technical support activities, and self assessment. The inspector concluded that the meeting was a good interchange of information.

5.2.3 Reports Review

The inspectors reviewed the July 1995 monthly operating report and the semi-annual fitness-for-duty program report (L-95-219). These reports were complete and accurate.

6.0 Plant Support (71750 and 93702)

6.1 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 programs; emergency preparedness; plant housekeeping/cleanliness conditions; and the radiological effluent, waste treatment, and environmental monitoring programs.

6.2 Inspection Findings

6.2.1 Hurricane Erin and Site Response

On July 30, 1995, at 11:30 p.m., a tropical storm watch was issued for the Turkey Point site due to the formation and projected track of a storm named Erin. As a precaution, the licensee voluntarily initiated steps for procedures 0-ONOP-103.3, Severe Weather Preparations and EPIP-20106, Natural Emergencies. At 11:25 p.m. on July 31, 1995, a hurricane warning was issued for the east coast of Florida including the site. The licensee declared an Unusual Event per procedure EPIP-20101, Duties of the Emergency Coordinator, and made all formal local, state, and NRC notifications within the required time. EPIP-20106 procedural steps were formally tracked and implemented.

The licensee tested all the site diesels including the four EDGs (3A, 3B, 4A and 4B), the S/B SGFP, the D service water pump, the DDFP, and the security diesel. Outside areas were cleared of debris that could become missiles in the wind, and remaining items were tied down. The flood protection stop logs were installed, selected areas were sand bagged, floor drain plugs were installed, portable pumps were staged, and preparations were made to shut down the units. Storm staffing plans were effected, sleeping and food arrangements were verified, and simulator training for the operations crews was conducted. Periodic management meetings were conducted to assess the storm preparations. The NPS continued as the emergency coordinator and EP personnel maintained awareness of storm updates and plots of the storm track, and communicated with NRC, state, and county personnel.

During the period July 31-August 1, 1995, Hurricane Erin proceeded in a WNW to NW direction off the Florida coast. At 8:20 p.m. on August 1, 1995, hurricane warnings were lifted for Dade County, FL, including the Turkey Point site. The licensee canceled the Unusual Event and notified the state and the NRC. Subsequently, EPIP actions were no longer required and were therefore reversed.

The inspectors performed the following actions in response to Hurricane Erin:

- monitored the Unusual Event declaration, report, and phone calls,
- verified implementation of the EPIPs and ONOP steps,
- verified completion of operator simulator training,
- attended periodic management meetings to assess site readiness,
- independently inspected the site including protected area, auxiliary building, RCA, and other buildings/areas,
- reviewed staffing and related personnel plans,
- independently verified the status of safety equipment and diesel operability,
- discussed planning and preparation activities with the NPS (emergency coordinator), operations, plant and site management, emergency preparedness personnel, and maintenance,
- reviewed plans for voluntary staffing of emergency response facilities (e.g., TSC, OSC, and EOF), and
- reviewed security preparations.

During the site walkdowns, the inspectors noted potential vulnerabilities from missiles including in the vicinity of the Unit 3 diesel fuel oil tank, the Unit 3 startup transformer, and the 4C bus transformer. The inspectors verified that the licensee's inspections had also noted these vulnerabilities and either had taken or planned actions to address.

Further, the Region II incident response center was also staffed to monitor hurricane related activities as well as provide assistance if needed.

The inspectors concluded that licensee demonstrated conservatism during hurricane preparations. Further, strong teamwork among site personnel and effective management oversight was noted. The hurricane did not significantly affect the plant and both units remained at full power through the hurricane watch and warning.

6.2.2 Non Credible Bomb Threat

On August 19, 1995, an anonymous bomb threat for Turkey Point was received by Metro Dade Police. Turkey Point was notified of the threat as well as representatives from the police department were sent to the site. The bomb threat was not deemed to be credible.

However, Turkey Point took appropriate precautionary measures. The resident inspector as well as the HDO were notified.

The inspectors concluded that the licensee appropriately responded to the threat.

6.2.3 Fitness For Duty Issue

On August 21, 1995, an FPL supervisor was confirmed positive was cocaine during a random drug test. The licensee determined that there was no indication of on-site use. The individual's access to Turkey Point and St. Lucie was revoked. Additionally, a review of the individual's work activities for the past 90 days was initiated. The licensee reported this incident to the NRC pursuant to the requirements of 10 CFR 26.73. The resident inspector was also notified.

The inspector concluded that the licensee appropriately reported and responded to the incident. The resident inspector plans to follow any future developments related this issue.

6.2.4 Work Practices

The inspector monitored licensee activities, including nuclear speakout, associated with work practices affecting personnel and occupational safety. This was accomplished through a review of a sample of speakout files, discussion with personnel, and observation of on-going work. The inspector determined that the licensee continues to have a strong safety program. Personnel injuries are monitored on a daily basis and management was found to be committed to tracking as well as preventing injuries. Personnel injuries were identified and discussed in the plan-of-the-day meetings. The inspector did not observe a hostile or violent work environment. The inspector also noted that the licensee was monitoring and trending personnel absence due to sickness and has set departmental goals to minimize absence. The inspector observed no impact on occupational or nuclear safety.

In conclusion, the licensee continues to have a strong occupational safety program with noteworthy management commitment.

7.0 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 September 6, 1995. (Refer to section 1.0 for exit meeting attendees.) 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. However, the inspectors had the following findings:

Item Number	Status, Description, and Reference
50-250,251/95-15-01	Non-Cited Violation, Inadequate Procedure Resulting in Both Containment Isolation Portion of Engineered Safeguards Trains Taken Out-of-Service Simultaneously (section 4.2.7)

8.0 Acronyms and Abbreviations

ADM	Administrative
AFW	Auxiliary Feedwater
a.m.	Ante Meridiem
ANPS	Assistant Nuclear Plant Supervisor
ANSI	American National Standards Institute
ARP	Annunciator Response Procedure
ASME	American Society of Mechanical Engineers
CNRB	Company Nuclear Review Board
CS	Containment Spray
CV	Control Valve
DDFP	Diesel Driven Fire Pump
DDPS	Digital Data Processing System
EDG	Emergency Diesel Generator
e.g.	For Example
EOF	Emergency Operating Facility
EOP	Emergency Operating Procedure
EP	Emergency Preparedness
EPIP	Emergency Plan Implementing Procedure
ERDADS	Emergency Response Data Acquisition and Display System
ESF	Engineered Safeguards Feature
°F	Degrees Fahrenheit
FPL	Florida Power and Light
FI	Flow Indicator
gpm	Gallons Per Minute
HDO	Headquarters Duty Officer
HHSI	High Head Safety Injection
I&C	Instrumentation and Control
IFS	Information Followup System
LCO	Limiting Condition for Operation
LER	Licensee Event Report
M&TE	Measuring and Test Equipment
MWe	Megawatts Electric
NI	Nuclear Instrument
NPS	Nuclear Plant Supervisor
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
ODI-CO	Operations Department Instruction
ONOP	Off-Normal Operating Procedure
OOS	Out of Service
OP	Operating Procedure
OSC	Operational Support Center
OSP	Operations Surveillance Procedure

PC/M	Plant Change/Modification
PDR	Public Document Room
p.m.	Post Meridiem
PMI	Preventive Maintenance - I&C
PMT	Post-Maintenance Test
PNSC	Plant Nuclear Safety Committee
PRT	Pressurizer Relief Tank
PSA	Probabilistic Safety Assessment
psig	Pounds Per Square Inch Gauge
PWO	Plant Work Order
QA	Quality Assurance
QC	Quality Control
RCA	Radiation Control Area
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RWST	Refueling Water Storage Tank
S/B SGFP	Standby Steam Generator Feed Pump
STA	Shift Technical Advisor
SV	Solenoid-Operated Valve
TSA	Temporary System Alteration
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
USC	U. S. Code
WCC	Work Control Center