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

Report Nos.: 50-250/92-28 and 50-251/92-28

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: October 31 through December 4, 1992

Inspectors: ______________________ 12/30/92
for R. C. Butcher, Senior Resident Inspector — Date Signed

______________________ 12/30/92
for G. A. Schnebli, Resident Inspector — Date Signed

______________________ 12/30/92
for L. Trocine, Resident Inspector — Date Signed

Accompanying Personnel

M. T. Janus, Reactor Engineer
C. W. Rapp, Reactor Inspector
S. J. Vias, Chief, Technical Support Staff

Approved by: ______________________ 12/30/92
K. D. Landis, Chief — Date Signed
Reactor Projects Section 2B
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspector inspection involved direct inspection at the site in the areas of monthly surveillance observations, monthly maintenance observations, engineered safety features walkdowns, operational safety, plant events, engineered safeguards integrated testing, Unit 3 startup from refueling, and management meeting. Backshift inspections were performed on November 3, 15, 17-20, 29-30, and December 1-4, 1992.

Results:

Within the scope of this inspection, the inspectors determined that the licensee continued to demonstrate satisfactory performance to ensure safe

plant operations. One violation, two non-cited violations, one apparent violation, one unresolved item**, one strength, and two weaknesses were identified as follows:

50-250,251/92-28-01, Non-cited Violation - Failure to meet the requirements of Technical Specification 3.9.4.c in that an airlock vent to atmosphere provided a direct path from the containment atmosphere to the outside atmosphere whenever the inner access hatch door was opened (paragraph 6.a).

50-250,251/92-28-02, Violation - Failure to properly lock fire protection water system valves in position (paragraph 7).

50-250,251/92-28-03, Unresolved - Determine how vent valve 3-737J was uncapped and opened (paragraph 9.b).

50-250,251/92-28-04, Non-cited Violation - Inadequate procedure for testing the B train of the Unit 3 Engineered Safeguards system resulting in the inadvertent automatic start of the 4B emergency diesel generator (paragraph 9.f).

50-250,251/92-28-05, Apparent Violation - Falsification of plant records (paragraph 8.b).

Strength - Operator actions in preventing a possible reactor trip (paragraph 9.c).

Weakness - (two examples) Failure to perform post maintenance testing on the B standby feedwater pump as soon as possible after completion of maintenance and inadequate review of the out-of-service log prior to de-energizing the A standby feedwater pump's power supply which resulted in both standby feedwater pumps being out of service at the same time (paragraph 9.a)

Weakness - Failure to clear known grounds in a timely manner (paragraph 9.c).

** Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations or deviations.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

* T. V. Abbatiello, Site Quality Manager
R. J. Earl, Quality Assurance Supervisor
R. J. Gianfrencesco, Support Services Supervisor
E. F. Hayes, Instrumentation and Controls Maintenance Supervisor
R. G. Heisterman, Mechanical Maintenance Supervisor
P. C. Higgins, Outage Manager
* D. E. Jernigan, Technical Manager
* H. H. Johnson, Operations Supervisor
* V. A. Kaminskas, Operations Manager
* J. E. Knorr, Regulatory Compliance Analyst
# R. S. Kundalkar, Engineering Manager
J. D. Lindsay, Health Physics Supervisor
G. L. Marsh, Reactor Engineering Supervisor
* L. W. Pearce, Plant General Manager
M. O. Pearce, Electrical Maintenance Supervisor
T. F. Plunkett, Site Vice President
D. R. Powell, Services Manager
* R. E. Rose, Nuclear Materials Manager
R. N. Steinke, Chemistry Supervisor
F. R. Timmons, Security Supervisor
M. B. Wayland, Maintenance Manager
* E. J. Weinkam, Licensing Manager

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

NRC Resident Inspectors

* R. C. Butcher, Senior Resident Inspector
* G. A. Schnebli, Resident Inspector
L. Trocine, Resident Inspector

Accompanying NRC Inspectors

* M. T. Janus, Reactor Engineer
C. W. Rapp, Reactor Inspector
S. J. Vias, Chief, Technical Support Staff

NRC Management on Site

H. N. Berkow, Project Directorate II-2, NRR
L. Raghaven, Licensing Project Manager (Acting), NRR
M. Sinkule, Branch Chief, Division of Reactor Projects, Region II

* Attended exit interview on December 4, 1992.

Attended management meeting on November 16, 1992.

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

2. Other NRC Inspections Performed During This Period

Report No.	Dates	Area Inspected
50-250,251/92-25	November 2 - 6, 1992	Radiation Control
50-250,251/92-27	November 2 - 6, 1992	In Service Inspection
50-250,251/92-29	November 16 - 20, 1992	Design Changes and Modifications
50-250,251/92-30	November 16 - 20, 1992	Electrical
50-250,251/92-31	November 16 - 20, 1992	Engineering and Technical Support
50-250,251/92-32	November 28 - December 3, 1992	Reactor Engineering
50-250,251/92-33	November 30 - December 4, 1992	Safeguard Inspection

3. Plant Status

Unit 3

At the beginning of this reporting period, Unit 3 was shut down for a refueling outage. The unit entered Mode 6 at 5:05 a.m. on October 1, 1992. The following evolutions occurred on this unit during this assessment period:

- At 11:50 p.m. on November 7, 1992, the unit entered Mode 5 when the reactor head bolts were tensioned.

- At 7:00 a.m. on November 24, 1992, the unit entered Mode 4.

- At 1:30 a.m. on November 25, 1992, the unit entered Mode 3.

- At 11:45 p.m. on November 25, 1992, Unit 3 started a cooldown from approximately 530°F due to an unisolable leak on a welded cap on a pressurizer spray valve leakoff line (Refer to paragraph 9.g for details). The unit entered Mode 4 at 3:00 a.m. on November 26, 1992, and Mode 5 at 8:10 a.m. on November 26, 1992.

- At 4:15 p.m. on November 27, 1992, Unit 3 entered Mode 4.

- At 2:15 a.m. on November 28, 1992, Unit 3 entered Mode 3.

- At 3:26 a.m. on December 1, 1992, Unit 3 entered Mode 2 for low power reactor physics testing. Criticality was achieved at 4:10 a.m. on December 1, 1991, and the unit re-entered Mode 3 at 12:23 a.m. on the following day when low power physics testing was completed.

- At 5:35 a.m. on December 2, 1992, Unit 3 entered Mode 2 in order to return to service, and criticality was achieved at 5:53 a.m.

- At 5:00 p.m. on December 3, 1992, the turbine roll was commenced; and at 5:40 p.m., Unit 3 entered Mode 1. At 6:16 p.m., while adjusting the governor oil impeller pressure in preparation for the main turbine trips test, turbine speed increased and operators manually tripped the turbine at approximately 1910 rpm and Mode 2 was re-entered. Following a post event critique, turbine roll was recommended at 7:05 p.m., Mode 1 was entered at 7:30 p.m. and the main turbine trip test, was successfully completed. A generator potential transformer problem occurred, and the turbine was tripped again at 9:37 p.m. Turbine roll was re-commenced at 10:15 p.m., Mode 1 was re-entered at 10:42 p.m., and the unit was placed on line at 11:10 p.m. on the same day. Reactor power was being increased for a chemistry hold at less than 30 % power.

Unit 4

At the beginning of this reporting period, Unit 4 was operating at 100% power and had been on line since October 27, 1992. The following evolutions occurred on this unit during this assessment period:

- At 10:30 p.m. on November 3, 1992, power was reduced to 87% for flux mapping. Power was returned to 100% at 2:45 p.m. on the following day.

- At 4:49 p.m. on November 11, 1992, a turbine runback occurred and power was stabilized at 50%. Power was returned to 100% at 7:00 a.m. the following day. (Refer to paragraph 9.c for details.)

- At 2:25 p.m. on November 14, 1992, a power reduction to 30% was initiated due to a secondary plant chemistry problem. Power was returned to 100% at 8:50 p.m. on November 16, 1992. (Refer to paragraph 9.d for details.)

4. Onsite Followup and In-Office Review of Written Reports of Nonroutine Events and 10 CFR Part 21 Reviews (90712/90713/92700)

The Licensee Event Reports and/or 10 CFR Part 21 Reports discussed below were reviewed. The inspectors verified that reporting requirements had been met, root cause analysis was performed, corrective actions appeared appropriate, and generic applicability had been considered. Additionally, the inspectors verified the licensee had reviewed each event, corrective actions were implemented, responsibility for corrective actions not fully completed was clearly assigned, safety questions had been evaluated and resolved, and violations of regulations or TS conditions had been identified. When applicable, the criteria of 10 CFR Part 2, Appendix C, were applied.

(Closed) LER 50-250/92-09, Hurricane Andrew at Turkey Point.

This event was discussed in detail in NRC IR 50-250,251/92-20. This LER is closed.

(Closed) LER 50-251/92-06, Two Mode Change Surveillances Not Performed in Accordance with Technical Specifications.

This issue was discussed in detail in NRC IR 50-250,251/92-20 and was identified as NCV 50-250,251/92-20-01. This LER is closed.

(Closed) LER 50-251/92-08, Lift of Pressurizer PORV PCV-4-455C and Isolation of MOV-4-751 Residual Heat Removal Suction During Overpressure Mitigating System Surveillance.

This event was discussed in detail in NRC IR 50-250,251/92-24 and was identified as NCV 50-250,251/92-24-01. This LER is closed.

5. Monthly Surveillance Observations (61726)

The inspectors observed TS required surveillance testing and verified that the test procedures conformed to the requirements of the TSs; testing was performed in accordance with adequate procedures; test instrumentation was calibrated; limiting conditions for operation were met; test results met acceptance criteria requirements and were reviewed by personnel other than the individual directing the test; deficiencies were identified, as appropriate, and were properly reviewed and resolved by management personnel; and system restoration was adequate. For completed tests, the inspectors verified testing frequencies were met and tests were performed by qualified individuals.

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

- 3-OSP-023.2, Diesel Generator 24 Hour Full Load Test and Load Rejection, for the 3A EDG;
- Section 7.2, Loss of Offsite Power Test, of 3-OSP-203.1, Train A Engineered Safeguards Integrated Test;
- Section 7.3, Safety Injection with Offsite Power Available, of 3-OSP-203.1, Train A Engineered Safeguards Integrated Test;
- Section 7.4, Loss of Offsite Power Coincident with Safety Injection, of 3-OSP-203.1, Train A Engineered Safeguards Integrated Test;
- Section 7.2, Loss of Offsite Power Test, of 3-OSP-203.2, Train B Engineered Safeguards Integrated Test;
- Section 7.3, Safety Injection with Offsite Power Available, of 3-OSP-203.2, Train B Engineered Safeguards Integrated Test;

- 3-OSP-072, Main Steam Isolation Valve Closure Test;
- 3-OSP-075.2, Auxiliary Feedwater Train 2 Operability Verification;
- 3-OSP-075.7, Auxiliary Feedwater Train 2 Backup Nitrogen Test;
- 4-OSP-075.7, Auxiliary Feedwater Train 2 Backup Nitrogen Test;
- 0-OSP-075.11, Auxiliary Feedwater Inservice Test;
- TP-926, Main Steam Code Safety Valve Set Point Verification Test; and
- OP-1004.1, Reactor Coolant System - System Leak Test Following RCS Opening.

The inspectors determined that the above testing activities were performed in a satisfactory manner and met the requirements of the TSs. Violations or deviations were not identified.

6. Monthly Maintenance Observations (62703)

Station maintenance activities of safety-related systems and components were observed and reviewed to ascertain they were conducted in accordance with approved procedures, regulatory guides, industry codes and standards, and in conformance with the TSs.

The following items were considered during this review, as appropriate: LCOs were met while components or systems were removed from service; approvals were obtained prior to initiating work; activities were accomplished using approved procedures and were inspected as applicable; procedures used were adequate to control the activity; troubleshooting activities were controlled and repair records accurately reflected the maintenance performed; functional testing and/or calibrations were performed prior to returning components or systems to service; QC records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were properly implemented; QC hold points were established and observed where required; fire prevention controls were implemented; outside contractor force activities were controlled in accordance with the approved QA program; and housekeeping was actively pursued.

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

- replacement of 3A EDG turbocharger due to loss of soakback pump (Refer to NRC IR 50-250,251/92-20 for additional information),
- troubleshooting of the Unit 3 containment air lock vent valve (Refer to paragraph 6.a below for additional information),

- troubleshooting of MOVATS testing of MOVs to determine cause of thrust value changes after test equipment was removed (Refer to paragraph 6.b below), and

- troubleshooting of the 3A 4-KV bus emergency tie to the Unit 4 startup transformer (breaker 3AA22) following the 3A 4-KV bus lockout (Refer to paragraph 9.e for additional information).

Other observations and/or inspections were as follows:

a. At 9:00 p.m. on October 31, 1992, licensee personnel identified that the Unit 3 containment PAH air lock vent to atmosphere ball valve, 3-S8A, was installed with the ball 90 degrees out of position. This condition was discovered when an individual stationed at the outer PAH noticed air whistling from the valve when it should have been shut. At the time of this event Unit 3 was in Mode 6 with core alterations in progress.

Valve 3-S8A is a 2 inch ball valve used for equalizing pressure between the inside of the PAH and the outside atmospheric pressure. An identical valve, 3-S8B, equalizes pressure between the inside of the PAH and the containment atmosphere. The valves positions are controlled by an interlock mechanism, such that when the respective PAH door is closed, the valve is also closed, thus preventing a direct path from the containment to the outside atmosphere. With the ball of the valve being installed 90 degrees out of its proper position, the valve was in the open position when indicated closed and in the closed position when indicated open. This condition resulted in a vent path from inside the containment to the atmosphere when the inner PAH door was open.

On October 10, 1992, maintenance was performed on valve 3-S8A to correct excessive seat leakage. At this time the ball was installed 90 degrees out of position due to personnel error. The valve's stem has a square end which permits it to be connected to the interlock mechanism in any one of four positions, two of which would be correct.

Core loading began at 8:50 a.m. on October 28, 1992, and ended at 6:55 p.m. on October 31, 1992. Therefore, the entire time core loading was in progress valve 3-S8A was inoperable, and a direct path from the containment to the atmosphere existed whenever the inner PAH door was opened for personnel/equipment access. Upon discovery of the improperly installed valve, core alterations were halted. The valve was re-installed to operate properly and a leak test was performed to verify correlation between valve position indication and actual valve position. In addition, procedure 3-OSP-51.6, Containment Air Lock Doors Operability Test, was revised to require a visual verification of ball valve position by inspecting the orientation of the position scribe mark on the ball valve stem.

TS 3.9.4.c. states that each penetration providing direct access from the containment atmosphere to the outside atmosphere shall be either closed by an isolation valve, blind flange, or manual valve, or be capable of being closed by an operable automatic containment isolation valve. However, on October 31, 1992, valve 3-S8A, Air Lock Vent to Atmosphere, was re-assembled incorrectly such that the valve provided a direct path from the containment atmosphere to the outside atmosphere whenever the inner access hatch door was opened. The failure to meet the requirements of TS 3.9.4.c. is a violation. However, this 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 Enforcement Policy. This violation will be tracked as NCV 50-250,251/92-28-01, failure the meet the requirements of TS 3.9.4.c in that an air lock vent to atmosphere provided a direct path from the containment atmosphere to the outside atmosphere whenever the inner access hatch door was opened.

b. Diagnostic testing of motor operated valves is presently being performed during the Turkey Point Unit 3 refueling outage in order to satisfy the requirements of NRC Generic Letter 89-10. Several MOVs have been tested to date and the actuator output thrust and torque has been measured by a combination of transducers. The transducers used to date include the ITT MOVATS supplied Torque Thrust Cell, ITT MOVATS supplied Thrust Measuring Device and the Teledyne supplied Quick Stem Sensor. These devices operate on the following principles:

- The TTC is a radial web calibrated load cell that bolts between the top of the valve yoke and the bottom of the actuator. The inner ring of the cell is bolted to the valve yoke and the outer ring to the bottom of the actuator. The rings are connected by eight webs that are strain gaged to measure actuator torque and thrust simultaneously. Note that the installation of the TTC requires that the actuator be raised the distance equal to the thickness of the TTC. This shifts the position of the actuator stem nut relative to the height of the valve stem.

- The TMD is a device that measures the displacement of the Limitorque actuator springpack. The TMD measures springpack displacement by means of a linear variable differential transmitter.

- The QSS is a strain gage mounted on a strip of foil with tabs on each end to facilitate installation on the valve stem. The sensor comes with leads preconnected to the gage. The QSS is installed on the valve stem using epoxy.

A typical diagnostic test consists of installing the TTC, TMD, and QSS on the MOV to be tested. (Note, however, that in some cases, the QSS cannot currently be installed on each valve stem due to the lack of adequate clearance.) The valve is stroke tested and the TTC is used as a calibration reference for the QSS. The calibration of the QSS allows it to be utilized for future MOV tests without the need to install the TTC. The Limitorque actuator torque switch is then set to produce the required valve stem thrust as specified in Minor Engineering Package PC/M 92-064 utilizing the TTC. After the TTC has been removed, a full valve stroke signature is obtained to evaluate overall actuator performance.

On November 9, 1992, ITT MOVATS engineers working at the site noticed that measurements taken with the TTC installed were differing from the stem mounted strain gage readings after the TTC was removed. The problem was first noted on MOV-3-869 when it was retested after failing a local leak rate test. Subsequent review showed that all of the valves that had been tested using the QSS changed somewhat when the TTC was removed from the valve. Data indicated that thrust readings degraded by approximately 20% when the TTC was removed.

On November 10, 1992, two members of MOVATS management and one senior engineer arrived at the site to investigate the differences. The MOVATS personnel and FPL engineering and maintenance developed an evaluation plan which included data analysis, checkout of all test equipment utilized, and inspections to determine the physical condition of the valve/actuator. Based on this evaluation, MOVATS personnel had the following conclusions:

- The most significant contributors to the observed changes in thrust when the TTC was removed are stem engagement and stem lubricant.

- Stem engagements of less than one stem diameter tend to increase the thrust at torque switch trip by improving the stem factor. This effect is more pronounced when Neolube is used than when EP-O is used as a stem lubricant.

- Test results indicate that stroke-to-stroke variations in thrust at torque switch trip are greater with Neolube than with EP-O. For Neolube, the variations tend to be high on initial lubrication and then decrease as the valve is stroked.

- Neither test equipment problems nor test personnel contributed to the observed changes. In addition, equipment accuracies did not appear to be a significant contributor to the results.

- Two of the valves (MOVs-4-535 and 3-536) showed a change in measured spring pack displacement that was significantly

greater than expected. Possible explanations are problems with the methodology for setting the switches, tampering with the torque switch, or a defective torque switch. The first of these is being investigated, the second is highly unlikely, and the third cannot be explored until the valves are available for inspection.

On November 20, 1992, FPL Engineering issued Safety Evaluation JPN-PTN-SEMP-92-037 to address MOVs affected by this issue. A copy of this evaluation was provided to Region II personnel for further review. For the purposes of the engineering evaluation, only the valve closing stroke information is tabulated. This is primarily due to the fact that QSS thrust information can only be obtained for the closing stroke after the TTC has been removed. QSS information in the opening direction can only be obtained by backseating the valve after the TTC has been removed, which is not recommended. In addition, the majority of the valves that require evaluation perform a safety related closing function. With regard to the opening stroke, all of the MOVs reviewed that have a torque switch in the opening valve circuit have the torque switch bypassed during the first 20% to 25% of the valve stroke. Bypassing of the open torque switch during this portion of the valve stroke enables the differential pressure and corresponding thrust load to be less than that required for initial valve opening. (This assumption will be validated as part of the dynamic MOV test results review required by NRC GL 89-10.) Therefore, the valve opening thrust value is not considered to be as critical as the closing thrust setting.

Eight valves (MOV-3-535, 3-536, 3-626, 3-866B, 3-869, 3-1403, 3-1404, and 3-1405) were tested with both the TTC and QSS. Both the corrected TTC and direct QSS thrust values have been compared to the required design thrust for these eight MOVs. In all cases, the corrected TTC thrust values are greater than the required design thrust. With the exception of MOV-3-1403, the direct QSS thrust readings are greater than the required design thrust. However, MOV-3-1404 only has 6.8% margin above design. Excluding MOV-3-1403 and MOV-3-1404, the lowest QSS thrust margin above design is 12.9% for MOV-3-536. Since MOVs-3-1403 and 3-1404 have a QSS margin of less than 7% above the design value, they shall be retested. The torque switch settings shall be increased, as necessary, in order to achieve sufficient thrust margin above design as measured by the QSS.

The remaining 16 MOVs identified were tested with only the TTC installed. In order to evaluate the potential thrust decrease upon removal of the TTC, a comparison of the TTC and QSS data for those MOVs instrumented with both devices has been performed. As stated above, MOVs-3-535, 3-536, 3-626, 3-866B, 3-869, 3-1403, 3-1404, and 3-1405 were tested with both the TTC and QSS. With the exception of MOV-3-866B, the difference between the TTC and QSS values vary between 7.7% and 22.2%. MOV-3-866B had a loose

connection between the actuator and bonnet. The connection was tightened just prior to the thrust increase indicted with the QSS reading. Tightening of this connection would increase the overall stiffness of the MOV and explain the thrust increase. For this reason, the negative difference between the TTC and QSS reading for MOV-3-866B was disregarded. Therefore, TTC and QSS thrust difference of 22.2% for MOV-3-1403 bounds the differences measured on the other MOVs tested in the field at Turkey Point. In addition, ITT MOVATS had performed testing in their facility to try to quantify the shift in TTC and QSS readings upon removal of the TTC. The testing was performed with a stem to stem nut lubricant of Neolube, which is the lubricant utilized at Turkey Point. The test results showed a 19% decrease in delivered thrust upon removal of the TTC.

All valves tested with the TTC have corrected TTC thrust values greater than the available thrust required by design. However, for the purposes of this evaluation, those MOVs that were tested with the TTC will have their corrected thrust readings degraded by 25%. A 25% degradation conservatively bounds the maximum degradation of 22.2% measured at Turkey Point and the 19% degradation measured at the ITT MOVATS test facility.

A review of the 25% degraded thrust TTC values showed that MOV-3-750, MOV-3-1425, MOV-3-1426, MOV-3-1427, MOV-3-1401, and MOV-3-6386 had sufficient margin in the TTC thrust measurements to account for 25% thrust degradation. However, MOV-3-751, MOV-3-856A, MOV-3-856B, MOV-3-866A, MOV-878A, MOV-878B, MOV-3-1400, MOV-3-1402, MOV-3-1420, and MOV-3-1421 did not have 25% degraded TTC thrust values above the required design thrust. Each of these MOVs was reviewed in detail to determine if the conservatively calculated required available design thrust values could be relaxed.

The engineering evaluation provided the following conclusions:

- MOVs tested with both the TTC and QSS (MOVs-3-535, 3-536, 3-626, 3-866B, 3-869, and 3-1405) have sufficient margin between the as-left thrust settings and the required design thrust.

- MOVs-3-1403 and 3-1404 do not appear to have adequate margin in the as-left QSS thrust settings. These valves shall be retested and the torque switch settings adjusted as necessary prior to unit startup.

- For those MOVs tested with only the TTC device, a conservative degradation of 25% of the corrected TTC thrust reading bounds the MOV testing performed at Turkey Point and testing performed by ITT MOVATS at their facility. This 25% TTC degradation accounts for the observed decrease in delivered thrust as the TTC is removed.

- A review of the 25% degraded thrust TTC values shows that MOV-3-750, MOV-3-1425, MOV-3-1426, MOV-3-1427, MOV-3-1401, and MOV-3-6386 have sufficient margin in the TTC thrust measurements to account for 25% thrust degradation when compared to the required design thrust.

- MOV-3-751, MOV-3-856A, MOV-3-856B, MOV-3-866A, MOV-878A, MOV-878B, MOV-3-1400, MOV-3-1402, MOV-3-1420, and MOV-3-1421 do not have sufficient thrust margin when the 25% degraded TTC value is compared to the original design thrust requirement. However, further review of each MOV concludes that sufficient margin does exist when their operational requirements are reviewed and conservatism is removed from the design thrust calculations.

- It should be noted that the relaxed differential pressures and relaxed MOV design thrust requirements discussed in this evaluation will not supersede the values previously established for the GL 89-10 MOV program. These relaxed values are only intended to demonstrate valve operability in the interim period until the diagnostic equipment differences are resolved.

This issue will continue to be reviewed by the NRC in the followup inspections for GL 89-10.

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. One non-cited violation was identified.

7. Engineered Safety Features Walkdown (71710)

The inspectors performed an inspection designed to verify the status of the Unit 3 and Unit 4 common fire protection system tanks, pumps, and supply lines to the system header. The inspection was performed after the normal fire water supplies had been fully repaired from damage caused by hurricane Andrew (including a new RWT 1) and fully restored to service at 2:00 p.m. on November 8, 1992. This inspection was accomplished by performing a complete walkdown of the tanks, pumps, and supply lines up to the fire water ring header, utilizing plant procedure 0-OP-016.1, Fire Protection Water System, and plant drawing 5610-T-E-4072, Revision 22, Operating Diagram Fire Protection System Tanks and Pumps. In addition, the inspectors performed a walkdown of the 3A EDG fuel oil, air start, cooling water, lube oil, and breaker alignment. This was accomplished by utilizing procedure 3-OP-023, Emergency Diesel Generator, and drawings 5610-T-E-4536, sheets 1 and 3. Some minor labeling and component deficiencies were noted and were brought to the attention of the system engineer for correction. The following criteria were used, as appropriate, during this inspection:

- systems lineup procedures matched plant drawings and as-built configuration;
- housekeeping was adequate, and appropriate levels of cleanliness were being maintained for the given ongoing service water construction activities in the area;
- valves in the system were correctly installed and did not exhibit signs of gross packing leakage, bent stems, missing handwheels, or improper labeling;
- hangers and supports were made up properly and aligned correctly;
- valves in the flow paths were in correct position as required by the applicable procedures with power available, and valves were locked/lock wired as required;
- local and remote position indication was compared, and remote instrumentation was functional; and
- major system components were properly labeled either with permanent or temporary identification tags.

While performing the system walkdown at approximately 3:00 p.m. on November 10, 1992, utilizing plant procedure 0-OP-016.1, Fire Protection Water System, and plant drawing 5610-T-E-4072, Revision 22, Operating Diagram Fire Protection System Tanks and Pumps; the inspectors identified three valves which were not properly locked in the required positions. Attachment 1 to procedure 0-OP-016.1 requires that valves 10-753, the Raw Water Tanks tie; 10-759, the full flow Recirculation Isolation valve; and 10-777, the Raw Water Tank II Outlet to the Jockey Pumps, be locked in the closed position. The inspector found the valves in the closed position; however, they were not properly locked in these positions. The locks were found secured to the valve yokes or around the chain operator and not through the handwheel or chain operator to prevent the operator from being easily moved as required in procedure 0-ADM-205, Administrative Control of Valves, Locks, and Switches. The inspector immediately notified the NPS and the noted conditions were corrected in a timely manner.

TS 6.8.1.h requires that written procedures be established, implemented, and maintained covering activities referenced in the Facility Fire Protection Program.

The Fire Protection Program, described in Appendix 9.6A of the facility Final Safety Analysis Report, paragraph 7.1, states:

> The Fire Protection Program at Turkey Point Units 3 and 4 is established by procedure. The Procedure shall provide surveillance and maintenance requirements for fire protection equipment and systems.

Procedure 0-OP-16.1, Fire Protection Water System, Attachment 1, Fire Protection Water System Valve Alignment, requires that valves 10-753, Raw Water Tanks Tie; 10-759, Full flow Recirculation Isolation; and 10-777, Raw Water Tank II Outlet to Jockey Pumps, be locked in the closed position. Administrative Procedure 0-ADM-205, Administrative Control of Valves, Locks, and Switches, stipulates that locked valves should prevent the operator from being easily moved.

However, on November 10, 1992, valves 10-753, 10-759, and 10-777 were found in the closed position but were not properly locked in position. The locks were secured to the valve yokes and not through the handwheels so as to prevent the operators from being easily moved to open the valves. This failure to follow a procedure is a violation and will be tracked as VIO 50-250,251/92-28-02, failure to properly lock fire protection water system valves in position.

One violation was identified. Except as noted in the violation, the fire protection system was in the final configuration with no discrepancies noted.

8. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs, conducted discussions with control room operators, observed shift turnovers, and monitored instrumentation. The inspectors verified proper valve/switch alignment of selected emergency systems, verified maintenance work orders had been submitted as required, and verified followup and prioritization of work was accomplished. The inspectors reviewed tagout records, verified compliance with TS LCOs, and verified the return to service of affected components.

By observation and direct interviews, verification was made that the physical security plan was being implemented. The implementation of radiological controls and plant housekeeping/cleanliness conditions were also observed.

Tours of the intake structure and diesel, auxiliary, control, and turbine buildings were conducted to observe plant equipment conditions including potential fire hazards, fluid leaks, and excessive vibrations.

The inspectors walked down accessible portions of the following safety-related systems/structures to verify proper valve/switch alignment:

- A and B emergency diesel generators,
- control room vertical panels and safeguards racks,
- intake cooling water structure,
- 4160-volt buses and 480-volt load and motor control centers,
- Unit 3 and 4 feedwater platforms,

- Unit 3 and 4 condensate storage tank area,
- auxiliary feedwater area,
- Unit 3 and 4 main steam platforms, and
- auxiliary building.

Other observations and/or inspections were as follows:

a. Unit 3 Operational Readiness

- The inspectors walked down the electrical portion of the AFW system in order to ensure that power supplies were available to all of the necessary valves for both Units 3 and 4. No discrepancies were noted. The inspectors also performed tours of the TSC to verify usability. As stated in NRC IR No. 50-250,251/92-24, all equipment appeared to be functional and the plant drawings and procedures were accessible. The tours also confirmed continuing progress on the repair of storm damaged ceilings and walls and on the replacement of storm damaged furniture. (Refer to paragraph 7 for a fire protection system walkdown.)

- The Unit 3 safeguards integrated tests were followed by the inspectors. (Refer to paragraph 10 for details.)

- In order to access Unit 3 system readiness prior to the performance of official system OSPs, the licensee developed and performed the following temporary procedures:

  * TP-919 AFW Readiness Test
  * TP-885 ICW System Readiness Test
  * TP-921 CCW System Readiness Test
  TP-920 Turbine Lube Oil System Readiness Test
  TP-917 Condensate System Readiness Test
  TP-918 Feedwater System Readiness Test

  * The asterisk indicates activities that were either completely or partially observed by the inspectors. These tests were accomplished during the performance of the Unit 3 Engineered Safeguards Integrated Test and various TPs, OPs and ISTs.

  Performance of these procedures (which involved the cycling of valves, the operation of pumps and fans, and the verification of position and operational status indications) prior to the performance of the official OSPs adequately demonstrated that components associated with various systems did not sustain any damage as a result of hurricane Andrew.

(Refer to paragraph 5 for a list of OSPs observed prior to or during the Unit 3 startup.)

- Most of the hurricane Andrew damage was repaired in preparation for the Unit 4 startup. However, there were a few Unit 3 specific repairs required. (For further details on the electrical system inspection refer to NRC IR No. 50-250,251/92-30.) The inspectors reviewed the following storm damage-related work items to verify the licensee's corrective action program was functioning:

  - o SJAE SPING - The Unit 3 SJAE SPING chiller system was heavily damaged during hurricane Andrew. The past operating experience of the SJAE SPING monitor indicated a high sensitivity to moisture intrusion and poor existing chiller reliability; therefore, PC/M 90-240 had been prepared to modify the system. The licensee elected to incorporate PC/M 90-240, RaD-3-6417 Sample Line and Cabinet Modifications, in lieu of repairing the existing system. PC/M 90-240 removed the existing RaD-3-6417 sample line chiller system and added a heat traced line to the cabinet, the existing drain trap on the water separator was replaced with a higher capacity model, and a small valve was installed to allow the operators to verify that the drain trap was working. In addition, the electronics cabinet was sealed to prevent entry of warm, moist, salt laden air, and a ventilation fan inside the cabinet was relocated. The inspectors verified PC/M 90-240 had been incorporated.

  - o Service Water Make-up to Circulating Water Pumps Pressure Controller, PC-3-1700 - The pressure controller is located in an exposed area at the intake structure and received minor damage. By work request No. 92044036, the licensee installed a new positioner cover, new gauge glass, and new gasket. The controller was leak checked, operationally checked, and placed in service.

  - o Exciter Voltage Regulator Enclosure - The existing exciter voltage regulator enclosure was heavily damaged during hurricane Andrew. The licensee removed the damaged enclosure and installed a new enclosure. The inspectors verified the new enclosure was in place.

  - o Process Radiation Monitor R3-17A - Monitor R3-17A, CCW Return Header Activity, stopped working sometime during hurricane Andrew. The licensee issued Work Request No. 92043493 to walk down the system and determine the cause for loss of indication. A blown fuse in the control room drawer was replaced per procedure 0-GMI-102.1, Troubleshooting and Repair Guidelines. Post maintenance tests per procedure AP-0190.28, Post Maintenance Testing, indicated proper operation following the fuse replacement.

- o Unit 4 EDG Building Air Conditioning Units Damaged - Under CWO No. 750054 the site construction group replaced all four air conditioning units on the roof of the Unit 4 EDG building. The air conditioning units were blown off the sheet metal duct work on the roof. The licensee is preparing an REA to add tie down structures around the air conditioning units on the EDG building roof to prevent recurrence. In addition, under CWO No. 750069, the site construction group repaired three of five ventilation exhaust hoods and installed two new ventilation exhaust hoods. The inspectors verified the noted work had been accomplished.

- At 1:00 p.m. on November 20, 1992, a CNRB meeting was convened at Turkey Point to review the Unit 3 readiness for restart. The Unit 3 startup readiness program presented was to verify that the requirements for work completion and operations have been met during the unit startup process following hurricane Andrew and refueling outage activities. The program elements are as follows:

  - o System readiness checklist
  - o Mode change checklist
  - o Mode 4
  - o Mode 2
  - o System readiness tests
  - o Restart open items list

  The CNRB approved the Turkey Point readiness for restart program.

- The system readiness checklists checked for clearances, system lineups, equipment OOS log, and system walkdowns having been completed. Subsequent to the above checklist completion, prior to entering Mode 4 (prior to 200°F) for 13 systems and prior to entering Mode 2 (reactor critical) for five other systems, the licensee verified a mode change checklist of the following items:

  - o plant cleanliness;
  - o fire protection impairments and equipment;
  - o QC activities - CAR, NCR;
  - o licensing activities;
  - o systems restoration;
  - o PC/M testing, turnover, and training;

- o surveillance completion;
- o restart punchlist work completion;
- o scaffold removal;
- o paper closure;
- o inspection system alterations;
- o condition reports; and
- o PWO closure for restart work.

- On November 25, 1992, at 11:30 a.m., a teleconference was conducted with NRC Region II and NRR management, senior licensee personnel and the NRC resident staff. The purpose of the call was to review the licensee's preparation and equipment status prior to Unit 3 entering Mode 2. Areas of discussion included the status of communications, hurricane damage corrective actions for Unit 3, plant personnel turnover and performance, licensee's lessons learned (near-term actions) complete, restoration of the fire protection system to normal, safeguards test results, and emergency preparedness status. Based on independent NRC inspection data and the licensee's restart plan, NRC management concurred with the licensee's restart schedule.

b. Verification of Plant Records

The licensee's efforts to conduct an independent review of the accuracy of plant records was previously discussed in NRC IR Nos. 50-250,251/92-13 and 92-16. The licensee's self-monitoring programs are described in those reports. By procedure ODI-CO-008, Operator Rounds Verification, the licensee identified a condition where an NPO (non-licensed) recorded required log readings without entering the required areas on October 27, 1992. These NPO log readings were required by procedure 4-OSP-201.3, NPO Daily Logs. The falsified log readings, on the main steam platform and the feedwater platform, are not TS required readings. The falsified readings verified main steam line penetration fans were running, the feedwater line penetration fans were running, and the turbine plant cooling water surge tank level and related control valves were normal. In response to this finding, the licensee terminated the employee. 10 CFR 50.9 requires, in part, that information required by the Commission's regulations, orders, or license conditions shall be complete and accurate in all material respects. TS 6.8.1 requires that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, dated February, 1978. Regulatory Guide 1.33 recommends procedures for operator logs. This finding is being reviewed as an apparent violation of 10 CFR 50.9 and will be identified as Apparent VIO 50-250,251/92-28-05, falsification of plant records.

c. The licensee routinely performs QA/QC audits/surveillances of activities required under its QA program and as requested by management. To assess the effectiveness of these licensee audits, the inspectors examined the status, scope, and findings of the following audit reports:

Audit Number	Number of Findings	Type of Audit
QAO-PTN-92-033	2	August/September Performance Monitoring Audit
QAO-PTN-92-035	-	Training and Qualification
QAO-PTN-92-040	1	October Performance Monitoring Audit

No additional NRC followup actions will be taken on the findings referenced above because they were identified by the licensee's QA program audits and corrective actions have either been completed or are currently underway. Plant management has also been made aware of these issues.

As a result of routine plant tours and various operational observations, the inspectors determined that the general plant and system material conditions were satisfactorily maintained, the plant security program was effective, and the overall performance of plant operations was good. Violations or deviations were not identified.

9. Plant Events (93702)

The following plant events were reviewed to determine facility status and the need for further followup action. Plant parameters were evaluated during transient response. The significance of the event was evaluated along with the performance of the appropriate safety systems and the actions taken by the licensee. The inspectors verified that required notifications were made to the NRC. Evaluations were performed relative to the need for additional NRC response to the event. Additionally, the following issues were examined, as appropriate: details regarding the cause of the event; event chronology; safety system performance; licensee compliance with approved procedures; radiological consequences, if any; and proposed corrective actions.

a. On November 3, 1992, at 11:45 a.m., the licensee notified the NRC, as required by TS 3.7.1.6.b.1., that both standby feedwater pumps were OOS at the same time. This condition was caused by the following sequence of events. On October 30, 1992, at 1:30 p.m., the B standby feedwater pump was removed from service for an oil change. Maintenance was completed later the same day; however, the pump was not returned to service because post maintenance testing was still required. At 1:30 p.m. on November 2, 1992, the 3C 4-KV bus was removed from service for planned maintenance. This bus supplies power to the A standby feedwater pump, which placed this pump OOS also. At 5:00 a.m. on November 3, 1992, licensee personnel discovered that both standby feedwater pumps were OOS at the same time, a condition for which TS 3.7.1.6.b.1 requires notification of the NRC within 24 hours. The B pump was

successfully post maintenance tested and returned to service at 5:54 a.m. on November 3, 1992, and the NRC was notified at 11:45 a.m. the same day. It should be noted the B pump would have started upon demand at any time during the A pump's supply bus outage; however, it was technically OOS until the PMT was complete. The failure to perform a PMT on the B standby feedwater pump as soon as possible after the completion of maintenance and an inadequate review of the OOS log prior to de-energizing the A pump's power supply are considered weaknesses.

b. At 5:55 p.m. on November 5, 1992, the Unit 3 RCO noted a rapid increase in containment sump level with no observed change in RCS level. At 5:57 p.m., the CCW surge tank level was observed to be decreasing, and the RCO closed MOV-3-730 and CV-3-739 to isolate the leak. CCW surge tank level stopped decreasing when CV-3-739 was closed. This valve had been opened in preparation for stroke time testing in accordance with step 7.11.8 of procedure 3-OSP-206.2, Quarterly Inservice Valve Testing. At 6:00 p.m., an NO inside containment reported water around the excess letdown heat exchanger. At 6:15 p.m., CV-3-739 was briefly opened and reclosed to identify the source of the leakage, and the NO reported that water sprayed from excess letdown heat exchanger vent valve 3-737J. Approximately 125 gallons of CCW water had leaked through this vent valve onto the containment floor. A walkdown of the excess letdown heat exchanger identified this vent valve as being open and uncapped. No other valves were out of position. A mechanical maintenance investigation showed that no work was being performed on the mispositioned valve, and a clearance computer check showed that there was no clearance on this valve. Subsequent to this event, vent valve 3-737J was closed and capped. Unit 3 was in Mode 6 at the time of this event and the excess letdown heat exchanger was not in service.

As a result of this event, operations personnel were instructed via a night order to add all vents and drains within the boundaries of the clearance as releasing steps on the clearance for verification of correct position prior to flow being initiated to a radioactive or non-radioactive system. The licensee has also added an item to its corrective actions list to revise procedure 0-ADM-212, In-Plant Equipment Clearance Orders, to include the verification of vent and drain positions prior to clearance release. This procedure revision is currently scheduled for completion on January 31, 1993.

The licensee is currently researching their records and interviewing personnel to determine how valve 3-737J was left open and uncapped. Until the licensee completes their review this event will be tracked as Unresolved Item 50-250,251/92-28-03.

c. At 4:49 p.m. on November 11, 1992, with the 3C transformer supplying both the 3C and 4C 4-KV buses, an electrician pulled breaker 3AC03 out of its cubical for relay maintenance. Because the breaker cubical door was not fully opened and latched, the breaker housing as it was being pulled made contact with a relay located on the door of the cubical and grounded a positive terminal to the relay. The resistance between this ground and a previously identified ground on breaker 3D31-8, which supplies the 3C bus transformer lockout relay electrical scheme, was low enough to allow the positive ground to pick up the 3C bus transfer lockout relay. This caused the opening of breaker 4AC01 and the subsequent loss of power to both the 4B feedwater pump and the B standby feedwater pump. The loss of the 4B feedwater pump resulted in a turbine runback from rated power and in the opening of a PORV. Because the control rods were in manual due to I&C work on N-44, they were manually inserted. In order to control the average versus reference RCS temperature difference and to minimize the rod insertion, the feedwater regulation and bypass valves were also fully opened, an additional charging pump was started, and heavy boration was commenced.

Operations controlled plant parameters during the runback and prevented a possible reactor trip. Operator actions during this event are considered to be a strength. Reactor power was stabilized at approximately 50% at 5:00 p.m., the 4C bus was re-energized at 9:35 p.m., and the B standby steam generator feedwater pump was returned to service at 10:55 p.m. Power ascension was commenced at 12:30 a.m. on November 12, 1992, and rated power was achieved at 7:00 a.m. on the same day.

Prior to this event, the A standby pump was taken out of service in order to facilitate 3C bus outage work. This placed both units in a 30-day LCO per TS 3.7.1.6.a for one standby feedwater pump being inoperable. When power was lost to the 4C bus at 4:49 p.m. on November 11, 1992, power was also lost to the B standby feedwater pump. Per TS 3.7.1.6.b.1, if both standby feedwater pumps became inoperable, the licensee is required to notify the NRC within 24 hours and provide the cause for inoperability and plans to restore the pumps to operable status. This event was reported to the NRC Operations Center at 11:20 p.m. on November 11, 1992.

This event would not have occurred if the pre-existing ground on breaker 3D31-8 had been cleared in a timely manner. A PWO to clear this ground was generated on October 29, 1992, and the event occurred on November 11, 1992. The failure to clear known grounds in a timely manner is considered to be a weakness.

As a result of this event, the licensee issued a night order emphasizing the importance of resolving grounding problems in a timely manner. In an effort to actively pursue the resolution of grounds, the licensee is now placing all grounds on the Hot Items List. The licensee has also reviewed the ERDADS data taken at the time of the event in order to enhance the ONOPs and improve operator training in order to better enable operators to prevent reactor trips on future loss of feedwater pump events.

d. At 2:25 p.m. on November 14, 1992, the chemistry department notified the NPS that Unit 4 had entered action level 2 of procedure 0-ADM-208, Secondary Plant Chemistry Control and Limits, due to high sodium levels in the SGs. The following sodium levels were recorded:

A SG	-	166 ppb
B SG	-	167 ppb
C SG	-	172 ppb

The SG blowdown rates were initially increased to approximately 60,000 lb/hr per SG. At 2:50 p.m., the DWST sodium concentration was 93 ppb, and SG blowdown was set at approximately 30,000 lb/hr per SG. As required by procedure 0-ADM-208, reactor power was reduced to less than 30% power. ONOP 1568.1, Secondary Chemistry - Operator Actions in the Event of Deviation from Limits, paragraph 5.4, High Sodium or Silica Concentration, step 8, states to adjust blowdown to reduce concentration, and step 9 states to follow the guidelines as specified in procedure 0-ADM-208. Procedure 0-ADM-208, paragraph 5.3, Steam Generator Parameters, step 5.3.3, Power Operation, defines action level 2 for sodium (ppb) as greater than 100 but less than or equal to 500 and requires less than or equal to 20 ppb for power escalation above 30%.

The source of the sodium contamination could not be readily determined, so a feed and bleed of the DWST was initiated to reduce sodium levels. By 9:40 a.m. on November 16, 1992, the sodium concentration had been reduced to the following:

A SG	-	10.1 ppb
B SG	-	10.1 ppb
C SG	-	9.8 ppb
DWST	-	8.8 ppb

At 11:06 a.m., a power increase to 100% was initiated, and Unit 4 reached 100% power at 8:50 p.m. on November 16, 1992. The cause of the event was determined to be CCW water leaking past check valve 3-10-517 during filling of the Unit 3 CCW surge tank. During this evolution, the surge tank level decreased about 500 gallons. A portion of this loss back-flowed through 3-724D, which is a normally closed valve, and past 3-10-517. The head pressure on this line filled the demineralized water lines leading to the lab tank and back to the DWST fill line from the WTP. When valve DWDS-001 was reopened to fill the DWST, a venturi effect pulled the CCW in the sample lines into the DWST. With the DWST (condenser make-up water) contaminated, the condenser then became contaminated leading to the sodium concentrating in the SGs. Corrective action is for valve 3-10-517 to be removed and replaced.

e. On November 16, 1992, the licensee was performing procedure 3-OSP-203.1, Train A Engineered Safeguards Integrated Test. As part of this test, the 3A EDG had been loaded onto the 3A 4-KV bus, for the 24-hour full load test and load rejection. At 7:52 a.m., the 3AA22 breaker (3A 4-KV bus emergency tie to Unit 4 startup transformer) was racked in to the test position and closed in conjunction with the safeguards test preparation, and a lockout occurred on the 3A 4-KV bus. The bus lockout resulted in a bus stripping signal which is an ESF actuation signal. All components performed as expected, and the event had no effect on Unit 4. The licensee reported this event per 10 CFR 50.72(b)(2)(ii), ESF Actuation, at 9:50 a.m. on the same day. (Refer to NRC IR 92-30 for additional information.)

f. On November 21, 1992, at 4:55 p.m., the licensee notified the NRC Operations Center in accordance with 10 CFR 50.72(b)(2)(ii) of an ESF actuation due to the automatic start of the 4B EDG during the Unit 3 safeguards testing. The event was caused by a technician lifting an incorrect lead from the safeguards relay 95Z1-3A in the emergency load sequencer cabinet. The licensee was in the process of performing procedure 3-OSP-203.2, Train B Engineered Safeguards Integrated Test, when the 4B EDG automatically started. An OTSC to the procedure was designed and implemented such that the 3A, 4A, and 4B EDGs would not start during this portion of the test. Lifting of the correct lead would have prevented the 4B EDG from automatically starting during this portion of the test. The 4B EDG automatically started at 2:10 p.m. on November 21, 1991, as the LOOP and SI portion of the test was initiated on the Unit 3 safeguards train B. The procedure directed the technician to the cabinet (3C 23B) and terminal board (348) but did not provide further guidance as to which of the three leads located on the terminal board (348) to lift. The technician lifted the lead he believed carried the input signal to start the 4B EDG.

Following the identification of this problem, the licensee implemented the following corrective action designed to prevent this problem from recurring in the future. Administrative procedure 0-ADM-101, Procedure Writer's Guide, was revised to include the following paragraph in the Instruction and Procedure Sections:

> For procedure steps which involve the lifting of a lead, or the installation of a jumper, for whatever purpose, the originator shall perform a field walkdown prior to procedure approval. This walkdown shall verify that sufficient detail (unique terminal and/or wire identification) is provided to allow performance of the step without misunderstanding or spurious (mis)operation.

The licensee also conducted a review of other existing guidance concerning lifting leads and jumpers and found that only new procedures lacked the specific guidance concerning this evolution.

The above stated revision to procedure 0-ADM-101, Procedures Writer's Guide, is intended to correct this deficiency and prevent it from happening again. The inspectors consider the corrective actions taken by the licensee to be adequate to resolve this issue.

TS 6.8.1.a requires that written procedures be established, implemented, and maintained covering activities recommended in Appendix A of RG 1.33, Revision 2, February 1978. Paragraph 8.b.1.1 of RG 1.33, Revision 2, February 1978, Appendix A, states that specific procedures for surveillance test, inspections, and calibrations should be written for reactor protection system tests and calibrations. Procedure 3-OSP-203.2 was written to test the Unit 3 train B engineered safeguards system. On November 21, 1992, when testing the B train of the Unit 3 engineered safeguards systems, the 4B EDG inadvertently started. Procedure 3-OSP-203.2 was inadequate in that it did not provide specific guidance as to which of the three leads on terminal board 348 were to be lifted.

This inadequate procedure is a violation. However, this 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. This item will be tracked as NCV 50-250,251/92-28-04, inadequate procedure for testing the B train of the Unit 3 Engineered Safeguards system resulting in the inadvertent automatic start of the 4B EDG. This item is considered closed.

g. At 6:25 p.m. on November 25, 1992, with Unit 3 at 530°F in Mode 3, the licensee declared a UE when it was determined that a small leak from a welded cap on a pressurizer spray valve leak-off line was an unisolable pressure boundary leak. Pressurizer spray valve PCV-3-455B has an unused leak-off line from below the packing area that had been welded closed. It was discovered during containment walkdowns that small wisps of steam were visible from the weld area. After it was determined that the leak was not isolable, the licensee declared a UE. The NRC was notified of the UE at 6:38 p.m. A cooldown was initiated at 11:45 p.m. on November 25, 1992. Unit 3 entered Mode 5 at 8:10 a.m. on November 26, 1992, and exited the UE. A weld repair was made to PCV-3-455B. Additionally, the unused leakoff line on the other pressurizer spray valve, PCV-3-455A, was reworked to ensure pressure boundary integrity. No further followup is necessary.

h. At 2:55 a.m. on November 27, 1992, with Unit 3 solid at 127°F and no RCPs running, the operators started the 3C RCP and PORV PCV-3-456 cycled twice due to high pressure. The operators observed 411 psig maximum. TS 3.4.9.3, Overpressure Mitigating Systems, action statement b.3 requires a special report to the NRC within 30 days. TS 3.4.1.3, Hot Shutdown, and procedure 3-OP-041.1, Reactor

Coolant Pump, paragraph 4.8 of Precautions/Limitations, states that an RCP shall not be started with one or more of the RCS cold leg temperatures less than or equal to 275°F unless the secondary water temperature of each SG is less than 50°F above each of the RCS cold leg temperatures. As a further conservation, procedure 3-OP-041.1, step 5.1.2.6, requires if the cold leg temperature is less than or equal to 275°F and no RCPs are running, then verify SG secondary water temperature is less than 10°F above the RCS temperature in 3A, 3B, or 3C SGs by one of several methods including temperature measurement of a representative secondary water sample obtained from each SG. The operators had recorded a SG blowdown temperature of 128°F and RCS T cold of 127°F. The inspectors will followup on the licensee's actions.

One non-cited violation, one unresolved item, one strength, and two weaknesses were identified.

10. Unit 3 Engineered Safeguards Integrated Testing (61701)

Prior to Unit 3 startup, the inspectors witnessed the majority of the safeguards testing for both trains A and B. The integrated testing of engineered safeguards and the emergency power systems was conducted for both trains A and B on November 17-21, 1992, under the guidance of procedures 3-OSP-203.1, Train A Engineered Safeguards Integrated Test, and 3-OSP-203.2, Train B Engineered Safeguards Integrated Test. These procedures provided the guidelines for test preparation, LOOP testing, SI with offsite power available testing, LOOP coincident with an SI testing, and plant restoration. (Refer to paragraph 5 for the list of tests which were observed by the inspectors.)

The LOOP test for each train was initiated by the temporary installation of a jumper at the load sequencer. These tests were performed within 5 minutes of completing procedure 3-OSP-023.2, Diesel Generator 24-Hour Full Load Test and Load Rejection. All work was coordinated so that the test preparations were completed by the end of the EDG 24-hour full load test. Near the end of the 24-hour run on the 3A EDG, the 3AA22 breaker (3A 4-KV bus emergency tie to Unit 4 startup transformer) was racked in to the test position and closed in conjunction with the safeguards test preparations, and a lockout occurred on the 3A 4-KV bus. (Refer to paragraph 9.e for additional information.) This was reported to the NRC Operations Center as an ESF actuation. As a result of this event, the 24-hour full load test had to be repeated. No further problems were identified.

The SI with offsite power available test for each train was initiated by the momentary depression of one of the SI initiation pushbuttons. No significant problems were identified.

The LOOP coincident with SI test for each train was initiated by the simultaneous opening of the respective startup transformer 4-KV bus supply breaker and the opening of the regulated nitrogen supply valve in the penetration room to simulate a high and high-high containment pressure.

The following problems occurred during the train A LOOP with SI test:

- The 3A SI pump did not start as required in section 7.4.23.2 because the pump was left in the pull to lock position on the Unit 4 console during the performance of the SI with offsite power available test. OTSC No. 10986 was written to clarify verification of pump control switch positions on both units' consoles. Section 7.4 of this procedure was repeated per OTSC No. 10973 and the 3A SI pump started properly.

- In addition, the 3H load center was thought to be disabled in Section 7.4 by tripping UV relays on the alternate train. These relays were believed to seal in but in actuality do not seal in and are self re-setting. This allowed the 3H load center to switch to its alternate power supply during the test. This problem was resolved by placing the test train feed breaker Normal/Isolate switch in Isolate. OTSC No. 10973 was written and approved to prevent the 3H load center from switching over during testing, and Section 7.4 of the procedure was successfully re-performed.

The following problems occurred during the train B LOOP with SI test:

- The 3B EDG frequency did not meet the acceptance criteria during the train B LOOP/SI test due to a failed relay. The relay was replaced, and the 3B EDG was re-tested successfully per OTSC No. 11000.

- During the 3B EDG frequency re-test per OTSC No. 11000, steps were added to lift three additional jumpers at the 3C23B sequencer cabinet to prevent starting of the 3A, 4A, and 4B EDGs (which would normally occur on an SI signal from the 3B train). The procedure identified the applicable terminal blocks but did not specify the wire numbers. As a result, an incorrect wire was lifted, and the 4B EDG start was not disabled. (Refer to paragraph 9.f for additional information on the inadvertent start of the 4B EDG during the train B LOOP with SI test.) This was also reported to the NRC Operations Center as an ESF actuation.

During the safeguards testing, the inspectors noted that the plant operators and engineers had received training on the tests and on the expected results. The inspectors also attended the pre-evolution briefings for various tests. The briefings covered the expected operating sequence of plant systems, personnel actions required, data to be taken, and precautions of the test procedure. Following the performance of each test section, appropriate appendices were used to record and verify the alignment and operation of all ESF components. The sequence of events recorders and EDG chart recordings were also used by the licensee to verify proper plant responses. The inspectors noted that if any component did not go to its intended position during the test or if any procedural discrepancies were noted, they were promptly documented, evaluated, and corrected. The repair of equipment problems identified during the testing was routinely completed prior to the performance of the next test. This approach allowed for an early re-test of the effected components. ESF component problems during the testing were minimal. In summary, the licensee's overall preparation, training, and management involvement was evident during the performance of these tests; and managements involvement assisted in obtaining the appropriate and prompt resolution of problems identified during the safeguards tests. Violations or deviations were not identified.

11. Plant Startup From Refueling (71711) Unit 3

The inspectors observed the Unit 3 reactor startup activities between November 29 and December 4, 1992, per procedure 3-GOP-301, Hot Standby to Power Operation. All major startup activities were observed in addition to the low power reactor physics testing. (Refer to NRC IR No. 50-250,251/92-32 for additional information.) Important elements observed were the briefings, management control of other work and activities, procedural adherence, operator attention to detail, and monitoring of nuclear performance. Unit 3 entered Mode 4 at 4:15 p.m. on November 27, 1992, and entered Mode 3 at 2:15 a.m. on the following day. Mode 2 was entered for low power physics testing at 3:26 a.m. on December 1, 1992, and criticality was achieved at 4:10 a.m. After the completion of the low power physics testing on December 2, 1992, Mode 3 was re-entered at 12:23 a.m. In order to return to service, Mode 2 was entered at 5:35 a.m., and criticality was achieved at 5:53 a.m. on the same day. At 5:00 p.m. on December 3, 1992, the turbine roll was commenced; and at 5:40 p.m., Unit 3 entered Mode 1. At 6:16 p.m., while adjusting the governor oil impeller pressure in preparation for the main turbine trips test, turbine speed increased and operators manually tripped the turbine at approximately 1910 rpm and Mode 2 was re-entered. Following a post event critique, turbine roll was recommenced at 7:05 p.m., Mode 1 was entered at 7:30 p.m., and the main turbine trips test was successfully completed. A generator potential transformer problem occurred, and the turbine was tripped again at 9:37 p.m. Turbine roll was re-commenced at 10:15 p.m., Mode 1 was re-entered at 10:42 p.m., and the unit was placed on the line at 11:10 p.m. on the same day.

12. Management Meetings (94702)

On November 16, 1992, at 8:30 a.m., NRC Region II management and NRR management met with FPL management to review the licensee's readiness to restart Unit 3. The licensee presented their restart activities required for plant startup. A tour of the Turkey Point site was conducted following the meeting.

13. Exit Interview (30703)

The inspection scope and findings were summarized during management interviews held throughout the reporting period with the Plant General

Manager and selected members of his staff. An exit meeting was conducted on December 4, 1992. 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	Description and Reference
50-250,251/92-28-01	NCV - Failure to meet the requirements of TS 3.9.4.c in that an air lock vent to atmosphere provided a direct path from the containment atmosphere to the outside atmosphere whenever the inner access latch door was opened (paragraph 6.a).
50-250,251/92-28-02	VIO - Failure to lock fire protection water system valves in position (paragraph 7).
50-250,251/92-28-03	Unresolved Item - Determine how vent valve 3-737J was left uncapped and open (paragraph 9.b).
50-250,251/92-28-04	NCV - Inadequate procedure for testing the B train of the Unit 3 Engineered Safeguards system resulting in the inadvertent automatic start of the 4B EDG (paragraph 9.f).
50-250,251/92-28-05	Apparent VIO - Falsification of plant records (paragraph 8.b).
Strength	Operator actions in preventing a possible reactor trip (paragraph 9.c).
Weakness	(two examples) Failure to perform PMT on the B Standby Feedwater pump as soon as possible after completion of maintenance and inadequate review of the OOS log prior to de-energizing the A standby feedwater pump's power supply which resulted in both SFW pumps being OOS at the same time (paragraph 9.a).
Weakness	Failure to clear known grounds in a timely manner (paragraph 9.c).

14. Acronyms and Abbreviations

ADM	Administrative
AFW	Auxiliary Feedwater
AP	Administrative Procedure
CAR	Corrective Action Request
CCW	Component Cooling Water
CFR	Code of Federal Regulations

CNRB	Company Nuclear Review Board
CV	Control Valve
CWO	Construction Work Order
DWST	Demineralized Water Storage Tank
EDG	Emergency Diesel Generator
ENS	Emergency Notification System
ERDADS	Emergency Response Data Acquisition Display System
ESF	Engineered Safety Feature
F	Fahrenheit
FPL	Florida Power & Light
GL	Generic Letter
GMI	General Maintenance I&C
GOP	General Operating Procedure
I&C	Instrumentation and Control
ICW	Intake Cooling Water
IR	Inspection Report
IST	Inservice Test
ITT	International Telephone and Telegraph
JPN	Juno Project Nuclear
KV	Kilovolt
lb/hr	Pounds Per Hour
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOOP	Loss of Offsite Power
MOV	Motor Operated Valve
MOVATS	Motor Operated Valve Actuator Test System
NCR	Non-conformance Report
NCV	Non-Cited Violation
NO	Nuclear Operator
NPO	Nuclear Plant Operator
NPS	Nuclear Plant Supervisor
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
ONOP	Off Normal Operating Procedure
OOS	Out of Service
OP	Operating Procedure
OSP	Operations Surveillance Procedure
OTSC	On-the-Spot Change
PAH	Personnel Access Hatch
PC	Pressure Controller
PC/M	Plant Change/Modification
PCV	Pressure Control Valve
PMT	Post Maintenance Test
PORV	Power Operated Relief Valve
ppb	Parts Per Billion
psig	Pounds Per Square Inch Gauge
PTN	Plant Turkey Nuclear
PWO	Plant Work Order
QA	Quality Assurance
QAO	Quality Assurance Organization
QC	Quality Control
QSS	Quick Stem Sensor

REA	Request For Engineering Assistance
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
rpm	Revolutions Per Minute
SFW	Standby Feedwater
SG	Steam Generator
SI	Safety Injection
SJAE	Steam Jet Air Ejector
T	Temperature
TMD	Thrust Measuring Device
TP	Temporary Procedure
TPCW	Turbine Plant Cooling Water
TS	Technical Specification
TSC	Technical Support Center
TTC	Torque Thrust Cell
UE	Unusual Event
UV	Under Voltage
VIO	Violation
WTP	Water Treatment Plant