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

Report Nos.: 50-250/94-23 and 50-251/94-23

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 30 through November 26, 1994

Inspectors: R. Schin for — 11/30/94
T. P. Johnson, Senior Resident Inspector — Date Signed

R. Schin for — 11/30/94
B. B. Desai, Resident Inspector — Date Signed

R. Schin for — 11/30/94
L. Trocine, Resident Inspector — Date Signed

Accompanied by: J. F. King, Intern, Office of Nuclear Reactor Regulation
R. P. Schin, Project Engineer, Reactor Projects Section 2B, Division of Reactor Projects

Approved by: — 11/30/94
for K. D. Landis, Chief — Date Signed
Reactor Projects Section 2B
Division of Reactor Projects

— 11/30/94
D. M. Verrelli, Chief — Date signed
Reactor Projects Branch 2
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 safety features walkdowns, operational safety, and plant events; maintenance including surveillance observations; engineering; plant support including radiological controls, chemistry, fire protection, and housekeeping; and a special review of two instances that the licensee identified which were outside the design basis. Backshift

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inspections were performed in accordance with Nuclear Regulatory Commission inspection guidance.

Results:

Within the scope of this inspection, the inspectors identified the following non-cited, cited, and apparent violations:

- Non-Cited Violation 50-250,251/94-23-01, Snubber Surveillance Program Problems (section 5.2.7)
- Violation 50-250,251/94-23-02, Failure to Follow Procedure Resulting in Inoperability of Two High Head Safety Injection Pumps (section 8.5.1)
- Apparent Violation 50-250,251/94-23-03, Failure to Meet 10 CFR Part 50, Appendix B, Criterion III, Design Control, Resulting in Inoperable Emergency Load Sequencers (section 8.5.2)

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

Plant Operations

The licensee's process to assure Unit 4 readiness for reactor heatup and startup was noteworthy (section 4.2.1). Safety system walkdowns concluded that the Unit 4 component cooling water and containment systems were satisfactorily aligned for normal and emergency operation (section 4.2.2). Unit 4 startup activities were well performed and were professionally conducted with strong oversight (section 4.2.3). Operations personnel promptly responded to several minor feedwater transients on Unit 4 and stabilized the unit in an efficient manner (sections 4.2.3 and 4.2.4). The procedure change process was determined to be well proceduralized, controlled, and documented (section 4.2.5). Control room operators inadvertently placed the 3A and 3B high head safety injection pumps in PULL-TO-STOP (pull-to-lock) during Unit 4 safeguards testing; this was a violation. Further, this operating error went undetected for over two hours including during a shift change. A licensee operations supervisor identified this condition and corrected it immediately. Followup by licensee management including an independent review and licensee event report submittal was timely and thorough. Corrective actions were complete and effective (section 8.5.1). Operators demonstrated excellent knowledge of emergency operating procedures during simulator scenarios (sections 8.5.1 and 8.5.2).

Maintenance

With the exception of one performance of the Unit 4 safeguards testing, inspector-observed station maintenance and surveillance testing activities were completed in a satisfactory manner (sections 5.2.1 and 5.2.2). The integrated safeguards testing on Unit 4 uncovered a design deficiency which existed in the emergency load sequencers (sections

5.2.3 and 8.0). The emergency diesel generator 24-hour full load test and load rejection test were professionally conducted; however, minor weaknesses were noted relative to operators' understanding of a test caution and implementation of a procedure change (section 5.2.4). The licensee's actions to ensure that risk-related activities were performed in a safe and controlled manner were noteworthy (section 5.2.5). Unit 4 local leak rate testing results were satisfactory (section 5.2.6). The inspectors identified a non-cited violation involving the failure to use a controlled document to determine the snubber surveillance functional test sample selection and the failure to document all of the functional test failures on the Functional Failure Documentation Sheet. The Functional Failure Documentation Sheet would ensure that snubbers that need to be retested due to failures are appropriately retested during the next refueling outage. The licensee's quality assurance department also performed a limited review of special processes and inservice inspection activities which included snubber testing and did not identify these issues (section 5.2.7). An open item regarding seat leakage for the power-operated relief valves was closed (section 5.2.8).

Engineering

Initial criticality and low power physics testing were professionally performed on Unit 4. The licensee also appropriately responded to a reactor coolant loop differential temperature issue (section 6.2.1). Onsite storage of diesel fuel oil met licensee commitments (section 6.2.2). Unit 4 main turbine trip modifications were appropriately performed (section 6.2.3). The licensee's internal review and disposition of NRC Information Notices was mixed. One response concerning air-operated valves was appropriate; however, another response concerning a sequencer automatic test problem at another plant was narrow in scope (sections 6.2.4 and 8.5.2). The failure to adequately perform, review, and test the emergency load sequencers design change performed in 1991 is an apparent violation. The licensee's response to this vulnerability including safety evaluations, engineering assessments, a licensee event report, and probabilistic reviews have been prompt and thorough (section 8.5.2).

Plant Support

The licensee's process to assure containment readiness to support Unit 4 restart was effective (section 7.2.1). The as-low-as-reasonably-achievable review committee was appropriately functioning and provided effective oversight (section 7.2.2). The licensee appropriately addressed onsite asbestos issues (section 7.2.3). The licensee proactively responded to a tropical storm warning, flood warning, and tornado watch which occurred in southern Florida (section 7.2.4). Lube oil was inappropriately left in a safety pump room, and this condition went unnoticed by plant personnel (section 7.2.5).

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REPORT DETAILS

1.0 Persons Contacted

1.1 Licensee Employees

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

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

1.2 NRC Resident Inspectors

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

1.3 Other NRC Personnel on Site

  J. F. King, Intern, Office of Nuclear Reactor Regulation
* K. D. Landis, Chief, Reactor Projects Section 2B, Division of Reactor Projects
  R. P. Schin, Project Engineer, Reactor Projects Section 2B, Division of Reactor Projects
  M. V. Sinkule, Chief, Reactor Projects Branch 3, Division of Reactor Projects

* Attended exit interview (Refer to section 9.0 for additional information.)

Note: An alphabetical tabulation of acronyms used in this report is listed in section 10.0 of this report.

2.0 Other NRC Inspection Performed During This Period

Report No.	Dates	Area Inspected
50-250,251/94-22	November 15-17, 1994	Personnel Screening

3.0 Plant Status

3.1 Unit 3

At the beginning of this reporting period, Unit 3 was operating at or near 100% reactor power and had been on line since May 27, 1994. The unit remained at or near full power during the inspection period.

3.2 Unit 4

At the beginning of this reporting period, Unit 4 was in Mode 5 as part of a planned refueling outage which began on October 3, 1994. Unit 4 entered Mode 4 on November 8, 1994, and Mode 3 on the following day. Mode 2 and criticality were achieved on November 11, 1994. Unit 4 was placed on line and entered Mode 1 on November 14, 1994. Following the turbine overspeed test, the unit was placed back on line and Mode 1 was re-entered on November 16, 1994. The unit achieved 100% reactor power on November 22, 1994. (Refer to section 4.2.3 for additional information.) A minor feedwater transient resulting in a loss of 70 MWe occurred on November 23, 1994. (Refer to section 4.2.4 for additional information.)

3.3 Management Changes

During the inspection period, L. W. Pearce resigned as Turkey Point Plant General Manager effective November 18, 1994. The licensee appointed D. E. Jernigan as the new Plant General Manager effective November 22, 1994; and H. H. Johnson as the new Operations Manager effective November 23, 1994.

4.0 Plant Operations (40500, 60710, 71707, 71711, and 93702)

4.1 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 and restart 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 CCW and containment systems. This was accomplished by performing a walkdown of all 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 and CNRB activities, QA/QC audits and reviews, line management self-assessments, individual self-checking techniques, and performance indicators.

4.2 Inspection Findings

4.2.1 Unit 4 Startup Readiness

In addition to the normal general operating procedural controls for heatup and startup (procedures 4-GOP-503, Cold Shutdown to Hot Standby, and 4-GOP-301, Hot Standby to Power Operation), the licensee performed independent verifications and checks by implementing temporary procedure TP-1065, Unit Restart Readiness. This process included the following activities:

- system engineer completion of readiness checklists for their specific systems;

- reviewed the clearance log, the equipment out-of-service log, PWOs, fire impairments, PC/Ms, TSAs, condition reports, system lineups, and surveillances;

- letters from each department head documenting readiness for restart;

- PNSC reviewed readiness; and

- final plant general manager review and determination.

The inspectors assessed the licensee's process, attended the related PNSC meetings, reviewed the completed TP-1065 procedure, and discussed the process with licensee management. The inspectors concluded that this process appeared effective and demonstrated conservatism in assuring that Unit 4 would be safely returned to service following the refueling outage.

The inspectors independently reviewed Unit 4 restart readiness by performing the following tasks:

- reviewed selected open and closed work items including post-maintenance testing, deficiencies, and commitments (e.g., condition reports, PWOs, PMAIs CTRAC items, etc.);

- verified system lineups and equipment availability by checking TSAs, system operating procedure checklists, the TSA log, clearances, and the equipment out-of-service log;

- toured the facility including the Unit 4 containment;

- reviewed control room instruments, alarms, and controls;

- reviewed general operating procedure implementation;

- reviewed operator training and readiness;

- reviewed outage PC/M completion, testing, and turnover;

- reviewed startup testing procedures and readiness;

- reviewed surveillance testing completion;

- reviewed and verified local leak rate testing and containment integrity; and

- reviewed ISI and erosion/corrosion inspections and repairs.

The inspectors concluded that Unit 4 was ready to support power operation. Two noteworthy items were operator training and management self-assessment. Reactor and plant startup training and modification training was given to all licensed operators. Management self-assessment included the procedure TP-1065 process discussed above.

4.2.2 Unit 4 CCW and Containment Systems Walkdown

The inspectors performed a walkdown designed to verify the status of the Unit 4 CCW system and the Unit 4 containment. This was accomplished by performing a complete walkdown of all accessible equipment. The following criteria were used, as appropriate, during this inspection:

- system lineup procedures matched plant drawings and as-build configuration;
- appropriate levels of housekeeping cleanliness were being maintained;
- 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;
- major system components were properly labeled;
- surveillance testing procedures and activities were appropriate; and
- maintenance activities (past, current, and planned) were appropriate.

The inspectors concluded that the Unit 4 CCW and containment systems were satisfactorily aligned for normal and emergency operation. Minor lineup and labelling deficiencies were discussed with engineering, operations, and maintenance personnel.

4.2.3 Unit 4 Startup From Refueling

Unit 4 entered Mode 4 at 4:50 p.m. on November 8, 1994; Mode 3 at 5:05 a.m. on November 9, 1994; and Mode 2 at 8:05 a.m. on November 1994. Criticality was achieved at 8:25 a.m. on November 11, 1994, and the licensee placed Unit 4 on line at 1:48 p.m. on November 14, 1994. This marked the completion of the Unit 4 refueling outage. This outage (which was originally planned to be 44 days in duration) was completed in 42 days. Mode 1 was entered at 1:52 p.m. on November 14, 1994, and reactor power was increased to approximately 30%. Following the performance of the turbine overspeed test on November 16, 1994, the licensee placed Unit 4 back on line, and Mode 1 was re-entered. Following holds at various power levels, the unit achieved 100% reactor power on November 22, 1994.

The inspectors observed startup activities, power ascension, turbine testing, and other related activities. The inspectors noted strong oversight and good communication and concluded that the Unit 4 startup was professionally conducted. The inspectors also noted that at the end of the inspection period, Unit 4 had achieved a "dark board" annunciator condition.

The inspectors observed operator response to feedwater level control problems associated with the 4B and 4C feedwater regulating valves. The licensee identified several component failures which were appropriately addressed. (Refer to section 5.2.1 for additional information.) The inspectors concluded that operator response was timely, efficient, and prevented major steam generator level transients.

4.2.4 Minor Unit 4 Feedwater Transient

At 10:10 p.m. on November 23, 1994, with Unit 4 at 100% reactor power, the low level alarm for the 4B HDT was received, and operators observed a higher than normal heater drain flow of approximately 8,000 gpm. Feedwater pump suction pressure decreased to approximately 240 psig, and the Unit 4 RCO started the third condensate pump. The 4B heater drain pump tripped on low HDT level at 10:11 p.m., and an NWE and NPO were dispatched to investigate the cause. At 10:15 p.m., the NWE reported that the alternate HDT dump was closed and that HDT level was oscillating slightly. The 4B heater drain pump was restarted at 10:20 p.m., and both heater drain pumps tripped on low HDT level at 10:25 p.m. In order to maintain feedwater pump suction pressure, the RCO opened feedwater heater bypass valve CV-4-2011 at 10:26 p.m. The 4A heater drain pump was restarted at 10:30 p.m. and was stopped again at 10:40 p.m. when the NWE requested I&C assistance due to the identification of a loose instrument air signal line from 4B HDT level controller LC-4-1510A to heater drain pump discharge control valve CV-4-1510A. It appeared that this line broke because of vibration and a lack of supports. This in turn caused valve CV-4-1510A to fail open. I&C personnel repaired the broken instrument air signal line fitting, and operators restarted the heater drain pumps at 10:48 p.m. The RCO also closed feedwater heater bypass valve CV-4-2011 at 10:50 p.m. This transient caused a loss of 70 MWe and secondary plant oscillations.

In addition, at 10:43 p.m., a secondary sample system trouble alarm was received, and chemistry was notified that steam generator cation conductivity was increasing. This increase was attributed to the introduction of water that had previously been stagnant in the feedwater heater bypass line until valve CV-4-2011 was opened. At 10:50 p.m., chemistry reported that all Unit 4 steam generators were in Action Level I for cation conductivity greater than 0.8 micromhos/cm. The licensee entered procedure 4-ONOP-071.1, Secondary Chemistry Deviation From Limits, and increased blowdown to 50,000 pounds mass per hour on each steam generator. At 11:10 p.m., chemistry reported that Action Level II had been entered for cation conductivity greater than 2.0 micromhos/cm. Action Level II was exited at 11:30 p.m., and the highest cation conductivity reached was 2.9 micromhos/cm. Chemistry reported that all action levels were exited at 1:40 a.m. on November 24, 1994.

As a result of this transient, the licensee generated condition report No. 94-1242 which recommended that all instrument air lines from level controllers to valves be walked down by I&C and/or engineering personnel and that additional supports be added where needed. The licensee also generated work request Nos. 94017768 and 94017769 to add supports to the instrument air signal line from level controller LC-4-1510A to control valve CV-4-1510A and to the instrument line to the control valve (valve CV-4-1517B) for the 6A high pressure heater dump to the condenser. Operators identified that the second line was not adequately supported and could be broken easily.

The inspectors reviewed the operating logs, the condition report, and the work requests and also discussed this event with operations and maintenance personnel. Operations personnel promptly responded to the event and stabilized the unit in an efficient manner. The inspectors plan to followup on the licensee's corrective actions during future inspections.

4.2.5 On-The-Spot Change Process For Changes to Procedures

The inspectors noted that the licensee had issued over 700 OTSCs to procedures in 1994. The inspectors reviewed the OTSC log and a sampling of about 30 1994 OTSCs to verify that the appropriate safety evaluation screening forms and approval signatures had been completed, that OTSCs had not been inappropriately used for intent changes to procedures, and that OTSCs were not routinely correcting significant procedure deficiencies that should have been corrected prior to a previous performance of the procedure. The inspectors also reviewed licensee procedures 0-ADM-102, On-The-Spot Changes to Procedures, and 0-ADM-100, Preparation, Revision, Review, Approval, and Use of Procedures.

Procedure 0-ADM-102 included an OTSC change of intent guidelines checklist that was to be completed for each OTSC to determine if the change constituted a change of intent of the procedure. Determination of change of intent then required PNSC review and plant general manager approval of the OTSC prior to use as required by the technical specifications.

The inspectors found that for the OTSCs reviewed, appropriate screening forms and signatures had been completed and that OTSCs without PNSC review and plant general manager approval had not inappropriately changed the intent of procedures. In addition, the OTSCs reviewed were not correcting significant procedure deficiencies that should have been corrected prior to a previous performance of the procedure. Most were for minor enhancements to procedures, for unusual plant configurations that may have been in

place during a performance of a procedure, or for corrections to a procedure that had not been used before.

The inspectors concluded that the licensee's OTSC process was well proceduralized, controlled, and documented.

5.0 Maintenance (61701, 61708, 61710, 61726, 62703, and 92902)

5.1 Inspection Scope

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

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

5.2 Inspection Findings

5.2.1 Maintenance Activities Witnessed

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

- replacement of Unit 4 relief valve (RV-209),
- troubleshooting of the Unit 4 feedwater regulating valves,
- Unit 3 rod control power supplies output and ripple power check for CRDM power cabinet negative DC power supplies PS-3 and PS-4 per WO No. 94027368-01 (Refer to section 5.2.5 for additional information.),
- troubleshooting of the Unit 3 and 4 turbine generators' hydraulic control systems (Refer to section 5.2.5 for additional information.), and
- modification and testing of the 4C and 3C electrical busses per PC/M No. 94-114. (Refer to section 5.2.5 for additional information.)

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

5.2.2 Surveillance Testing Activities Observed

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

- procedure 4-OSP-075.7, Auxiliary Feedwater Train 2 Backup Nitrogen Test;

- procedure 4-PMI-028.3, RPI Hot Calibration, CRDM Stepping Test, and Rod Drop Test;

- procedure 4-OSP-203.1, Train A Engineered Safeguards Integrated Test (Refer to sections 5.2.3 and 8.0 for additional information.);

- procedure 4-OSP-203.2, Train B Engineered Safeguards Integrated Test (Refer to section 5.2.3 for additional information.);

- procedure 4-OSP-023.2, Diesel Generator 24-Hour Full Load Test and Load Rejection (Refer to section 5.2.4 for additional information.);

- local leak rate testing results documented in procedure 4-OSP-051.5, Local Leak Rate Tests (Refer to section 5.2.6 for additional information.);

- procedure 0-OSP-040.5, Nuclear Design Verification (Refer to section 6.2.1 for additional information.);

- procedure 0-OSP-040.6, Initial Criticality After Refueling (Refer to section 6.2.1 for additional information.);

- procedure 3-OSP-024.2, Emergency Bus Load Sequencers Manual Test (Refer to section 8.5.1 for additional information.); and

- sequencer testing in the training center (Refer to section 8.5.2 for additional information.)

The inspectors determined that with the exception of the initial train A safeguards test on Unit 4, the above testing activities were performed in a satisfactory manner and met the requirements of the technical specifications.

5.2.3 Unit 4 Integrated Safeguards Testing

The licensee performed Unit 4 procedure 4-OSP-203.1, Train A Engineered Safeguards Integrated Test, and procedure 4-OSP-203.2, Train B Engineered Safeguards Integrated Test, during the Cycle 15 refueling outage. Technical specifications required testing various engineered safeguards features including SI with and

without LOOP, containment phase A and B isolation, LOOP, feedwater isolation, main steam line isolation, control room ventilation isolation, and containment ventilation isolation.

A problem involving failure of the 3A HHSI pump to start occurred during section 7.4 of train A safeguards testing. Additionally, during recovery from that test, the 3A and 3B HHSI pumps were inadvertently placed in pull-to-lock. (Refer to section 8.0 for details.) Section 7.4 of the test procedure was subsequently repeated without any further problems. Train B safeguards was also successfully completed.

The inspectors observed major portions of both train A and train B safeguards testing. The inspectors concluded that with the exception of the operating error noted in section 8.0 of this report, testing was satisfactorily performed.

5.2.4 Emergency Diesel Generator Full Load Testing

The inspectors observed portions of the 4A and 4B EDG testing performed per procedure 4-OSP-023.2, Diesel Generator 24-Hour Full Load Test and Load Rejection. During the test, the inspectors observed good licensee test preparations and communications.

While observing the test, the inspectors noted that action step 11.b.2, which required operators to adjust EDG reactive load to between 0 and 200 KVAR out with the EDG at its full rated load of 2750 KW, was inconsistent with a caution prior to step 11 that stated: "The 4B EDG voltage and amperage shall be maintained within the limits of enclosure 1." When operators adjusted the EDG voltage regulator to attain a reactive load of between 0 and 200 KVAR out, the EDG amperage was about 380. However, the acceptable operating range shown in Figure 1 was about 440 to 460 amps. At that point, the inspectors questioned the system engineer and operator. The licensee subsequently held the test procedure at step 11.2.b until the discrepancy was resolved by issuing an OTSC to the procedure. This changed step 11.b.2 to allow a higher range of reactive load (KVAR out) which enabled operators to maintain the EDG amperes within the limits of enclosure 1.

The inspectors independently verified the appropriate EDG reactive load during this test. The inspectors estimated a power factor of about 0.8 for plant loads during a LOCA event and calculated an EDG full load KVAR that compared well with the actual KVAR which operators attained while loading the EDG to within the limits of enclosure 1. Comparison with licensee engineers' calculations found that they were similar. The inspectors checked the procedure for Unit 3 EDG testing and found that it did not have a similar problem. Unit 3 EDGs did not have an installed KVAR meter, and the Unit 3 procedure appropriately required EDG load to be adjusted to within the limits of its enclosure 1.

The inspectors reviewed the records of the previous test performed on the 4B EDG to see how the above noted inconsistency had been addressed. The inspectors found that the licensee had made a procedure change to a number of steps to address inconsistencies between the steps that required KVAR out between 0 and 200 and other steps that required voltage and amperage to be within the limits of enclosure 1. After step 11.b.2, operators had recorded EDG KVAR out between 0 and 200. After a subsequent step, operators had adjusted EDG load to be within the limits of enclosure 1 prior to the start of the 24-hour period that was counted for the test.

The inspectors concluded that the 4B EDG had been appropriately loaded during the previous test. The inspectors also concluded that during that test, operators did not fully understand the caution prior to step 11 when they performed step 11.b.2. In addition, the licensee's procedure change (OTSC) for that test had been incomplete in that it had overlooked the inconsistency between the caution and step 11.b.2. The licensee initiated corrective actions to address these issues.

5.2.5 Administrative Controls Using the Red Sheet Process

Licensee management utilizes a red sheet process as an additional licensee control system for the performance of risk-related activities. This process ensures that appropriate levels of management have reviewed potential work-related risks, and it also requires plant general manager review and approval.

This process requires that the work group fill out a red sheet if work could affect (or have the potential to affect if in close proximity) any of the following systems or components: RPS; phase A or B containment or ventilation isolation; the ECCS and ESF systems; the CRDM and RPI systems; AMSAC/ATWS; the main steam, condensate, feedwater, and heater drain systems; the turbine and turbine generator systems, the 4KV/480V distribution, vital AC instrumentation, and vital DC systems; the switchyard; the inverters; welding or digging in the power block; or operations or maintenance surveillance procedures associated with the above systems. A separate red sheet is required for each train. This process ensures that the following potential problems have been reviewed for applicability: potential errors that could cause a loss of load or unit trip; potential valving errors that could cause hydraulic perturbations for common sensing lines; multiple wires in single terminals; instrument or PC board removal or installation; physical limitation of the work area; placement of jumpers without banana jacks or other permanent connections; work on sensitive equipment or that could potentially affect sensitive equipment such as inverters, NIS, protection racks, Rosemount transmitters, etc; and NPS/ANPS evaluation for potential adverse

effects from work on systems shared between the fossil and nuclear units as well as those shared between Units 3 and 4.

The inspectors reviewed the licensee's red sheet process and the licensee's implementation of this process for three risk-related work activities. These activities included a power check for output and ripple on Unit 3 CRDM power cabinet negative DC power supplies PS-3 and PS-4, the repair of a leaking Swagelok fitting on a Unit 3 governor impeller oil sensing line, and 3C/4C 4KV-bus post-modification testing for PC/M No. 94-114. The inspectors attended the pre-evolutionary briefings and various management meetings where troubleshooting activities and risks were discussed. The inspectors also witnessed portions of these work activities as they occurred. The licensee's actions to ensure that these risk-related activities were performed in a safe and controlled manner were noteworthy.

5.2.6 Unit 4 Containment Local Leak Rate Testing Results

The licensee performed as-found and as-left containment local leak rate testing during the Unit 4 Cycle 15 refueling outage. The inspectors reviewed several type B and C containment local leak rate tests that had been performed pursuant to the requirements of 10 CFR Part 50, Appendix J. This was documented in NRC Inspection Report No. 50-250,251/94-20. The inspectors reviewed and discussed the overall results of the completed local leak rate testing performed on Unit 4. The as-left total type B and C local leak rate on Unit 4 following the Cycle 15 refueling outage was 12,127 cc/minute. The acceptance criteria (less than 0.6 La) was 45,000 cc/minute. Further, the inspectors reviewed the as-found leak rate data. Although not required, a qualitative assessment of the as-found data was performed by the licensee, which found that the as-found leak rate was satisfactory. The licensee is not required to perform a qualitative assessment of this data; however, an assessment by the licensee determined that the as-found leak rate was satisfactory.

The inspectors noted that three valves in separate penetrations had excessive as-found leakage. In each case, the redundant valve's leak rate was satisfactory. The licensee repaired those three leaking valves. The inspectors concluded that the as-left leakage was within the acceptance criteria and that it was appropriately documented in procedure 4-OSP-051.5, Local Leak Rate Tests.

5.2.7 Snubber Surveillance Program Review

Technical Specification 4.7.6 and ASME Section XI defined the requirements for the performance of visual examination and functional testing of all safety-related mechanical shock arrestors. In order to meet the visual examination requirements, the licensee utilized procedure OP-0209.9, Visual Examination of

Mechanical Shock Arrestors. The licensee also hand stroked and visually examined all snubbers (both safety-related and quality-related) during each refueling outage. In addition, the licensee utilized administrative procedure AP-0190.83, Mechanical Shock Arrestor Surveillance Program, and administrative procedure AP-0190.85, Functional Testing of Mechanical Shock Arrestors, to meet the functional testing requirements. During the Unit 4 Cycle 15 refueling outage, a vendor performed the visual examinations, hand stroking, and functional testing of the Unit 4 snubbers.

The inspectors reviewed the licensee's snubber surveillance program and applicable documentation including Technical Specifications 3.7.6 and 4.7.6 and the applicable technical specification bases; administrative procedures AP-0190.83 and AP-0190.85; the current Unit 4 refueling outage visual and functional testing report; the computer generated Unit 3 and 4 mechanical shock arrestor master snubber and hanger information files; various site grid snubber locator maps; OTSC Nos. 654-94 and 768-94 to procedure AP-0190.83; attachment 1, Functional Sample Selection Documentation Sheet, of procedure AP-0190.83 for the Cycle 15 Unit 4 refueling outage; attachment 2, Functional Failure Documentation Sheet, of procedure AP-0190.83 for the Cycle 15 Unit 4 refueling outage; condition reports Nos. 94-992, 94-1011, 94-1038, and 94-1039; and QA Performance Monitoring Report No. 4 (QA audit No. QAO-PTN-94-024) dated November 14, 1994. The inspectors also discussed the snubber surveillance program with the ISI coordinator and with plant management and observed selected snubber functional tests.

During this program review, the inspectors questioned the representative functional testing sample selection and functional testing failure documentation processes. Technical Specification 4.7.6.d(1) required, among other things, that at least 10% of the total number of safety-related snubbers for the respective unit be functionally tested during the refueling outage, and Technical Specification 4.7.6.d(2) required that at least 25% of the snubbers in the 10% representative sample include snubbers located within 5 feet of heavy equipment or within 10 feet of the discharge from safety relief valves. These requirements were also documented in steps 8.1.2 and 8.1.4 of procedure AP-0190.83 and in a note on attachment 1 of the same procedure. Step 8.1.3 of this procedure also required that the snubbers selected for testing be listed on attachment 1. In addition, step 8.1.8 required that all snubbers that failed functional testing be documented on attachment 2 of procedure AP-0190.83 including snubber locations and serial numbers.

- Representative Functional Testing Sample Selection Process

  The October 3, 1994, Functional Sample Selection Documentation Sheet (attachment 1 of procedure AP-0190.83) for the recent Unit 4 refueling outage documented that there

were a total of 91 safety-related snubbers on Unit 4 and that 10 snubbers were selected for the representative functional test sample. This met the 10% sample size criteria. The documentation sheet also listed the tag numbers (snubber locations) for the ten snubbers in the representative sample as well as the tag numbers for snubbers which failed the previous functional test and were repaired, tested, and re-installed; replacement snubbers in locations that failed the previous functional test; and snubbers which were functionally tested for information only. In addition, the documentation sheet indicated that four out of the ten representative sample snubbers were within five feet of heavy equipment and that none were within ten feet of the discharge from safety relief valves. This met the 25% criteria. However, after comparing the tag numbers from the snubbers in the representative sample to the Unit 4 Mechanical Shock Arrestor Surveillance Program table (enclosure 2 of procedure AP-0190.83), the inspectors identified that only one of the representative sample snubbers was listed as being within 5 feet of heavy equipment. One was less than the 25% criteria.

Subsequent discussions with the ISI coordinator revealed that the mechanical shock arrestor master hanger information file was in the process of being revised and that the information documented on attachment 1 of procedure AP-0190.83 was taken from an April 26, 1994, informal list with hand written changes in lieu of the PNSC-approved list in enclosure 2 of procedure AP-0190.83 which was dated May 26, 1994. The informal updated list did document four out of the ten representative snubbers as being within five feet of heavy equipment, and the inspectors verified that the snubbers whose criteria had changed were in fact within five feet of heavy equipment (spatially versus in line with). The licensee concurred that a procedure revision or OTSC should have incorporated the updated listing prior to sample selection on October 3, 1994.

In order to correct this issue, the licensee issued OTSC No. 768-94 on November 22, 1994, to incorporate the updated snubber listing. Although this OTSC did not require PNSC approval, it was PNSC approved on November 25, 1994. In addition, the licensee reviewed the categorization of the snubbers tested during the Unit 3 refueling outage earlier this year and confirmed that the categorization agreed with the listing provided in the approved procedure (which was correct) at the time the testing was performed.

- Functional Testing Failure Documentation Process

The inspectors also compared the failures documented by condition reports to the failures documented in the November

7, 1994, Functional Failure Documentation Sheet (attachment 2 of procedure AP-0190.83) and determined that the failure data listed on the documentation sheet was incomplete. The functional test failure of snubber No. 4-1044 (which was a snubber that was additionally tested by the licensee) was documented in condition report No. 94-1038 but was not documented on the Functional Failure Documentation Sheet as required by step 8.1.8 of procedure AP-0190.83. In addition, the functional test failure of snubber No. 4-1039 (which was a replacement snubber in a location which failed the previous functional test) was documented in condition report No. 94-1039 but was only listed by its serial number (No. 6998) as being disposed of on the Functional Failure Documentation Sheet. It was important to have all snubber failures documented on attachment 2 of procedure AP-0190.83 because the licensee utilized this attachment to determine which snubbers need to be retested during the next refueling outage.

In order to correct these discrepancies, the licensee issued a supplement to attachment 2 of procedure AP-0190.83 on November 21, 1994, to appropriately document the functional failures of snubber Nos. 4-1039 and 4-1044 as required by step 8.1.8 of procedure AP-0190.83. An overall procedure change to clarify the requirement for listing functional test failures and to upgrade this procedure to a new format is currently ongoing and is scheduled to be completed consistent with the administrative upgrade project. The licensee also performed a review of the data from the previous two refueling outages on each unit prior to 1994 and ensured that all functional test failures had been listed and that appropriate testing had been preformed.

The licensee's QA department performed a limited review of special processes and ISI activities which included a review of snubber testing. This audit (QA audit No. QAO-PTN-94-024) was documented in QA Performance Monitoring Report No. 4 dated November 14, 1994. The licensee's audit included, among other things, a review of the sampling plan for compliance with the technical specification 10% selection requirement and review of the corrective actions taken for failed snubbers. The issues identified above were not identified by the QA department.

The failure to use a controlled document to determine the snubber surveillance functional test sample selection and the failure to document all of the functional test failures on the Functional Failure Documentation Sheet to ensure that snubbers that need to be retested due to failures are appropriately tested during the next refueling outage are considered to be two examples of one violation. However, this violation will not be subject to enforcement action because of the low safety significance of the violation and because the licensee's efforts in correcting the violation meet the criteria specified in Section VII.B(1) of the NRC Enforcement Policy. This item is identified as NCV 50-250,251/94-23-01, Snubber Surveillance Program Problems. This item is closed.

5.2.8 Power-Operated Relief Valve Seat Leakage Open Item (URI 50-250,251/94-05-03)

The licensee repaired both Unit 4 PORVs per procedure 0-PMM-041.1, Reactor Coolant System Power Operated Relief Valves Overhaul. The PORVs are two-inch, Copes-Vulcan, air-operated, plug valves with an internal cage. PORV PCV-4-456 was leaking prior to the Unit 4 shutdown for refueling, and condition report No. 94-1017 identified that the valve cage would not fully seat into the valve body because it was about 7 mils out-of-round. The licensee machined the body and repaired the valve. Mockup training was performed prior to the actual performance of the work done on top of the pressurizer.

The inspectors reviewed the procedure, PWO, condition report, and other related documentation. The inspectors also observed in-field work (Refer to NRC Inspection Report No. 50-250,251/94-20 for additional information.) and the training mockup in the maintenance shop. The inspectors concluded that procedure implementation was appropriate. The mockup training was noteworthy. After the unit startup, the repaired PORVs did not leak. Based on this, the URI is closed.

6.0 Engineering (37551, 90712, 90713, and 92700)

6.1 Inspection Scope

The inspectors verified that licensee engineering problems and incidents were properly reviewed and assessed for root cause determination and corrective actions. They accomplished 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 reviewed selected PC/Ms including the applicable safety evaluation, in-field walkdowns, as-built drawings, associated procedure changes and training, modification testing, and changes to maintenance programs.

The inspectors also reviewed the Monthly Operating Report 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.

6.2 Inspection Findings

6.2.1 New Core Initial Criticality, Zero Power Physics Testing, and Power Escalation

Initial criticality after refueling on Unit 4 was performed per procedure 0-OSP-040.6, Initial Criticality After Refueling, and zero power physics testing was performed per procedure 0-OSP-040.5, Nuclear Design Verification. These Unit 4 tests verified certain nuclear design parameters. These included all rods out critical boron concentration, hot zero power differential boron worth, control rod group worth, and isothermal moderator and temperature coefficients.

During power escalation, the operators noted that the loop C delta T was higher than the loop A and B delta Ts. At 95% power, the loop C delta T was approximately 3°F higher than the other two loops. This resulted in annunciator alarms on numerous occasions due to delta T deviation. A condition report was initiated, and an ERT was subsequently formed to resolve this issue. The ERT evaluated several possible causes and concluded that the most likely cause for the delta T deviation was a more pronounced hot leg streaming on the C loop due to a low leakage core at BOL with a small radial power tilt in the quadrant close to the C hot leg. Additionally, the RTD arrangement on the C loop (as compared to the A and B loops) was such that the streaming phenomenon was easily observed. Streaming has been observed on several Westinghouse plants and is a function of the core flux profile that causes thermal gradients in RCS hot legs. The licensee also discussed the issue with a Westinghouse representative and reviewed Westinghouse Technical Bulletin NSD-TB-92-15-RO dated January 22, 1993, associated with this phenomenon. The ERT and the PNSC concluded that power escalation to 100% would not be affected nor would there be any impact on plant safety.

The inspectors observed portions of the criticality and testing. For the portions observed, the inspectors concluded that appropriate procedure steps and precautions were followed. The inspectors concluded that personnel involved were knowledgeable of the process and equipment. Sufficient supervisory attention was also noted. The measured values were in agreement with the predicted core design values. Additionally, the inspectors attended ERT meetings regarding the delta T deviation issue and reviewed the licensee's evaluation. The inspectors concluded that the licensee aggressively and appropriately dispositioned the issue.

6.2.2 Emergency Diesel Generator Fuel Oil Supply

The inspectors reviewed the EDG fuel oil supply at Turkey Point. The Unit 3 (3A and 3B) EDGs share a common fuel oil storage tank, while the Unit 4 (4A and 4B) EDGs each have a dedicated fuel oil storage tank. Technical Specification 3.8.1.1.b requires minimum capacities of 38,000 gallons for Unit 3, and 34,700 gallons for each Unit 4 tank. This allows for a 7-day supply of fuel oil for 3A or 3B EDGs and for the 4A and 4B EDGs. (Refer to NRC Inspection Report No. 50-250,251/91-14 for additional information.)

The inspectors reviewed FPL calculation PTN-SFJM-92-004 and IC-TP. 000IR2 for Units 3 and 4, respectively. These calculations confirmed and documented the above technical specification requirements. The inspectors concluded that the licensee met its design basis.

6.2.3 Unit 4 Main Turbine Trip Modifications

The licensee performed PC/Ms on the main turbine hydraulic control system effecting trip logic as follows:

- PC/M No. 93-150 changed the low pressure turbine steam inlet pressure setpoint for overspeed protection. Pressure switch PS-4-3639 was changed to 70 psig or 50% reactor power equivalent. This function closes the turbine control and intercept valves if the generator load is less than 20%.

- PC/M No. 94-072 replaced the governor and load limit (2L) valve motors and removed the low low load limit (4L) device. The motors were modified with upgraded and improved DC motors. The licensee concluded that the 4L device was unnecessary and should therefore be removed.

- PC/M No. 94-75 relocated the 20/ASB backup trip solenoid device allowing it to remain functional during turbine front standard testing. Previously, when the turbine test handle was engaged, the 20/ASB device and turbine trip logic were bypassed. Vendor recommendations due to recent industry events resulted in a similar PC/M being performed on Unit 3 during the last refueling outage. The 20/ASB connection point was moved to the high pressure oil supply side of the test handle.

The inspectors reviewed the PC/M packages including safety and engineering evaluations, drawings, process sheets, change notices, procedure changes, equipment listings, turnover documentation, and post-modification testing. The inspectors also examined in-field installations and discussed the PC/Ms with licensee personnel and witnessed main turbine trip and overspeed testing. The inspectors concluded that the above mentioned PC/Ms were satisfactorily implemented.

6.2.4 Replacement of Solenoid-Actuated Air-Operated Valves

In response to NRC Information Notice 88-24 associated with failures of air-operated valves, the licensee replaced several valves on Unit 4 during the Cycle 14 refueling outage during April 1993 and on Unit 3 during the Cycle 14 refueling outage during May 1994. The licensee tracked this issue as internal commitment CTRAC No. 93-0719-03.

The inspectors reviewed licensee activities associated with this issue for Unit 3 and the results were documented in NRC Inspection Report No. 50-250,251/94-10. Further, the inspectors reviewed the activities associated with Unit 4 during this inspection period. The inspectors concluded that the licensee appropriately met their internal commitment as it applied to Units 3 and 4.

6.2.5 Monthly Operating Report

The inspectors reviewed the October 1994 monthly operating report and determined it to be complete and accurate.

7.0 Plant Support (71750)

7.1 Inspection Scope

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

7.2 Inspection Findings

7.2.1 Unit 4 Containment Closeout Inspection

On November 8, 1994, the inspectors toured the Unit 4 containment in order to assess readiness for reactor heatup and startup. The entry was performed per procedure 0-ADM-009, Containment Entry when Integrity is Established. The inspectors checked for fluid leaks, equipment material condition, housekeeping issues, radiological conditions, and readiness to support mode changes. The inspectors noted a few deficiencies; however, licensee QA/QC and management inspection had previously identified these items. The items were either being correcting or planned to be corrected prior to restart. The inspectors verified that these issues were appropriately addressed.

The inspectors concluded that the licensee's process to assure containment readiness for restart was effective. The inspectors did not identify any compliance issues.

7.2.2 ALARA Review Committee

The inspectors attended an ALARA review committee meeting on November 1, 1994. The meeting was attended by the appropriate licensee personnel. Topics discussed included Unit 4 reactor cavity drain system hot spots and the Unit 4 outage exposure review.

Radiation hot spots in the Unit 4 containment were identified on October 29-30, 1994, on reactor cavity drain valves 4-12-001 and 4-12-002. These valves are located on the 14-foot elevation in a locked cage area. Dose rate readings with high range detectors (RO7 and Teletector) indicated a contact reading of 840 Rem/hour on one valve and 30 Rem/hour on the other valve. The ALARA review committee discussed possible causes and corrective actions. Apparently, these valves have been historical crud traps during reactor cavity draindowns. During outages, the valves are equipped with drain devices to direct water to the containment sump. During power operations, the valves are locked open with the drain flanges removed. This provides a drain path from the lower reactor cavity in order to direct CS water to the ECCS sumps. The licensee considered a process to flush this hot spot radioactivity to a filter rig; however, this was not done due to uncertainties in storage, transfer, and processing of this material. The committee recommended allowing the material to decay and reducing exposure by shielding the hot spots for the remainder of the outage and by leaving the radioactive material in the valves until the next Unit 4 refueling outage.

The inspectors reviewed the hot spot issue including the proposed flush procedure, survey sheets, and committee meeting minutes. The inspectors noted that the hot spot areas were appropriately identified and controlled and that the area was locked. General area radiation areas within the locked gate ranged from 3 Rem/hour to 40 mRem/hour.

The inspectors noted that the outage exposure goal was increased from 175 Rem to 230 Rem due to emergent work and rework. The inspectors intend to review outage exposure as part of the Unit 4 refueling outage critique.

The inspectors concluded that the licensee's ALARA review committee was appropriately functioning and that the committee provided effective oversight and critical reviews of health physics issues.

7.2.3 Unit 4 Turbine Asbestos Issues

During the Unit 4 outage, asbestos was encountered during the high pressure turbine overhaul. The inspectors reviewed the asbestos sampling and abatement programs, attended meetings held with contractor personnel, discussed the issue with licensee safety and

management personnel, inspected areas associated with the high pressure turbine, and reviewed asbestos awareness training programs.

The inspectors learned of a visit by an OSHA inspector on November 2, 1994, to followup on a complaint related to this issue. The inspectors talked to the OSHA inspector following the site visit. The OSHA inspector did not identify any personnel safety violations to the NRC or to the licensee.

7.2.4 Tropical Storm Gordon

South Florida was affected by Tropical Storm Gordon during the period November 12-17, 1994. At 4:00 a.m. on November 14, 1994, a tropical storm warning was issued for the area. The licensee implemented procedure 0-ONOP-103.3, Severe Weather Preparations. The area experienced heavy rains, 40-50 mph winds, and tornado and flood watches. The licensee entered the ONOP on the weekend before the warning was issued. The storm did not adversely effect the station. The licensee maintained contact with local authorities. The Turkey Point evacuation routes were not effected.

The inspectors monitored ONOP implementation, inspected plant areas for possible wind or water damage, and monitored security system performance and associated compensatory actions. The inspectors noted that ONOP implementation was not required to be logged in the RCO log book. The inspectors questioned this issue, and the licensee stated that it would review its current practice. The inspectors concluded that the licensee proactively entered the ONOP prior to storm warnings and took appropriate actions.

7.2.5 Transient Combustibles in the 4A Residual Heat Removal Pump Room

During the walkdown of the Unit 4 CCW system, the inspectors noted that approximately one gallon of lube oil was stored next to the 4A RHR pump. The oil was in a capped, one gallon, clear, plastic container. The inspectors notified the fire protection supervisor who confirmed the inspectors' observation and immediately ordered the oil to be removed. Additionally, a condition report was originated to determine the circumstances surrounding the issue. The oil had apparently been in the 4A RHR pump room since the performance of RHR motor maintenance activities during the refueling outage. The transient combustible program requirement as described in procedure 0-ADM-016.1, Transient Combustible and Flammable Substance Program, required the oil to be removed and placed in approved containers in designated storage areas. The reason the oil was left next to the 4A RHR pump has not been determined.

The inspectors plan to follow up on this issue through the resolution of the condition report. The inspectors concluded that

the oil should not have been left next to the 4A RHR pump and, more importantly, that it went unnoticed by plant personnel. The ADM limit for combustible material was five gallons; and therefore, this one gallon container of oil was below that limit.

8.0 Conditions Outside The Design Basis

8.1 Background and Introduction

The Turkey Point HHSI system is a shared system between Units 3 and 4. Each unit supplies two HHSI pumps with suction from the unit's RWST. The system discharges into a common header which can then supply either unit's safety injection cold or hot legs. The licensing basis (Technical Specification 3.5.2) requires that all four HHSI pumps be operable for dual unit operation and that three HHSI pumps be operable for single unit operation. UFSAR sections 6.2, 14.2, and 14.3 and the safety injection design basis document (5610-062-DB-001) assume that two HHSI pumps are available to mitigate the consequences of an accident. Thus, for single unit operation, three operable HHSI pumps with a single pump failure meets the two required HHSI pumps accident criteria. Each of the four HHSI pumps has a redundant control switch on Unit 3 and Unit 4 control boards. The switch positions are START, AUTO, and PULL-TO-STOP. The PULL-TO-STOP position is called pull-to-lock by the operators and will be so identified throughout this report. The switch spring returns to AUTO unless it is in pull-to-lock.

The Turkey Point emergency load sequencers are designed to stop non-safety equipment and start safety equipment on the 4KV vital buses during design basis accidents with or without off-site power available. Each 4KV vital bus (3A, 3B, 4A, and 4B) has an associated emergency load sequencer (C23 panel) which is described in UFSAR section 8.2 and the emergency power system design basis document (5610-023-DB-001). There are no technical specifications that directly address the operability of the sequencers; however, Technical Specification 3.3.2 (ESF actuation instrumentation) does address specific sequencer functions. Also, surveillance testing of the sequencers is required by Technical Specification 4.8.1.1.2.g (diesel generators). The sequencers are Class 1E, Seismic 1, and are required to mitigate the consequences of an accident. The sequencers were installed during the 1990-1991 dual unit outage. The sequencers are software driven programmable logic controllers and have a manual and automatic test mode of operation. The hardware was designed by Allen-Bradley, and the software was supplied by United Controls, Inc. The sequencers are designed to respond to accident signals (LOCA, LOOP, or LOCA/LOOP). Upon actuation, the sequencer will cause loads to strip off the vital bus and will then sequentially load safety equipment either on the EDG or on off-site power. Equipment affected includes HHSI pumps, CS pumps, RHR pumps, CCW and ICW pumps, ECC and ECF units, and load center breakers.

On November 3, 1994, the licensee identified two events in which Turkey Point was considered to be outside the design basis. The first event occurred when two HHSI pumps were inadvertently placed in pull-to-lock and, therefore, were not available to automatically start in case of an accident. The second event occurred when the licensee identified a design deficiency in all of the four emergency load sequencers. The following sections discuss these two events.

8.2 Sequence of Events

Date(s)	Time(s)	Event(s)
1987		PC/M No. 87-264 was initiated to install the 4A and 4B EDGs as well as the 3A, 3B, 4A, and 4B emergency load sequencers.
1987 to 1991		Design, installation, and testing activities associated with the emergency load sequencers were performed. (Refer to NRC Inspection Report Nos. 50-250,251/91-14, 50-250,251/91-22, 50-250,251/91-35, and 50-250,251/91-39 for additional information.)
10/90		Factory testing (verification and validation) per procedure SATP3A2 was completed on the sequencers.
07/91		Preoperational tests were completed on the sequencers after installation per POP-0804 series procedures.
09/20/91		The 3A and 3B emergency load sequencers were placed in service on Unit 3.
10/28/91		The 4A and 4B emergency load sequencers were placed in service on Unit 4.
12/10/91		The 4A emergency load sequencer was declared out of service due to a failed automatic test output card relay. As corrective action, all four sequencers were taken out of the automatic test mode. (NRC Inspection Report No. 50-250,251/92-02 and LER 50-251/91-007 discussed the issue.)

Date(s) (Continued)	Time(s)	Event(s)
12/91 to 11/92		Unit 3 operated with the automatic test function in off.
12/91 to 05/93		Unit 4 operated with the automatic test function in off.
03/26/92		A Unit 4 inadvertent SI/reactor trip event occurred. Safeguards equipment and sequencers (automatic test in off) functioned as expected. (Refer to LER 50-251/92-004 for additional information.)
08/24/92		An actual LOOP occurred on Units 3 and 4 during Hurricane Andrew. All four sequencers activated and functioned as required. (Refer to LER 50-250/92-009 for additional information.)
10/92 and 05/93		PC/M Nos. 92-033 and 92-034 were implemented on Units 3 and 4 to modify the automatic test logic such that the test was performed every 60 minutes versus every 3 minutes. After completion of the modification, the licensee returned all four sequencers to the automatic test mode. (NRC Inspection Report No. 50-250,251/92-30 discussed the issue.)
11/16/92		An unplanned LOOP occurred on Unit 3 during testing of the 3A EDG. This was a valid challenge to the sequencer, and it performed adequately with the test function in automatic. (Refer to LER 50-250/92-013 for additional information.)
11/92		Unit 3 safeguards testing was performed satisfactorily with the test function in automatic.
05/93		Unit 4 safeguards testing was performed satisfactorily with the test function in automatic.

Date(s) (Continued)	Time(s)	Event(s)
05/05/94		During safeguards racks re-energization with Unit 3 in a refueling outage, an inadvertent 3A train ESF actuation occurred, and the 4A HHSI pump did not start as required. Investigation of the 3A and 4A sequencer panels did not reveal any malfunctions. (Refer to NRC Inspection Report No. 50-250,251/94-10 for additional information.)
05/94		Unit 3 safeguards testing was performed satisfactorily.
11/02/94		The licensee commenced train A safeguards testing during the Unit 4 refueling outage. The LOOP and LOCA portions of the testing were satisfactorily completed with no major problems. Following completion of the LOCA portion; the 3A, 3B, 4A, and 4B HHSI pumps' control switches were verified to be in the automatic position.
11/03/94	8:35 a.m.	The LOOP/LOCA portion of the Unit 4 train A safeguards test was initiated.
11/03/94	8:37 a.m.	The 3A HHSI pump failed to start as required. All other components including 3B HHSI and 4A HHSI pumps and the 4A CS pump started as required. Safeguards test personnel noted the deficiency and proceeded with the test. Plant personnel reviewed possible causes for the failure.

Date(s) (Continued)	Time(s)	Event(s)
11/03/94	9:06 a.m.	The 3A and 3B HHSI pumps and 4A CS pumps were put in pull-to-lock. Step 7.4.26 of the safeguards procedure required the pumps to be placed in the stop position. Presumably, the test director inadvertently misread the step and said pull-to-lock instead of stop or the RO performing the action misheard the request. With the 4A HHSI pump administratively inoperable, this placed Unit 3 in a Technical Specification 3.0.3 LCO. Placing the 3A and 3B HHSI pumps in pull-to-lock caused the annunciator for each of the pumps to come in on the Unit 3 and 4 sides of the control room. The Unit 3 RO acknowledged the annunciators and assumed that they were related to safeguards testing ongoing on Unit 4.
11/03/94	9:35 a.m.	Manual testing of the 3A sequencer was completed satisfactorily.
11/03/94	9:50 a.m.	The Unit 3 ANPS discussed the two annunciators associated with the 3A and 3B HHSI pumps with the Unit 3 RO and both were under the assumption that the condition was acceptable and related to Unit 4 safeguards testing.
11/03/94	10:00 a.m. to 11:00 a.m.	Shift turnover occurred. The test director and Unit 3 RO remained on shift, and the Unit 3 ANPS, Unit 4 ANPS, and NPS were relieved. The incoming and outgoing Unit 3 ANPSs discussed the annunciators and accepted them as normal. The incoming Unit 4 ANPS did not note any deficiencies on Unit 4. The incoming NPS noted the 3B HHSI in pull-to-lock but did not question the condition.

Date(s) (Continued)	Time(s)	Event(s)
11/03/94 (Continued)	10:00 a.m. to 11:00 a.m.	Efforts were underway to begin troubleshooting of an apparent 3A sequencer failure.
11/03/94	11:45 a.m.	I&C personnel went to the control room to request permission to begin troubleshooting the 3A emergency load sequencer problem per a PWO. An RO supporting activities on Unit 4 noted that the 3A HHSI pump switch would have to be taken out of pull-to-lock to accommodate the testing per the PWO. The Unit 4 ANPS gave permission to take the 3A HHSI pump out of pull-to-lock. The 3A HHSI pump switch was returned to AUTO. The Unit 4 ANPS also discussed with the NPS that the 3A HHSI pump was out of pull-to-lock for I&C troubleshooting. The operations supervisor, who was in the control room, overheard this and questioned the reason for the 3A HHSI pump being in pull-to-lock. The Unit 4 ANPS and the operations supervisor examined the panel and noted that the 3B HHSI pump was in pull-to-lock. Upon seeing this, the 3B HHSI pump switch was taken out of pull-to-lock. This restored the operability of the 3B HHSI pump. All three required HHSI pumps were returned to an operable status for Unit 3. The licensee concluded that Unit 3 was in Technical Specification 3.0.3 and had been since 9:06 a.m. Operations contacted licensing to evaluate reportability.
11/03/94	1:00 p.m.	I&C personnel completed troubleshooting on the 3A sequencer and did not identify any obvious abnormalities.

Date(s) (Continued)	Time(s)	Event(s)
11/03/94	1:00 p.m. to 4:00 p.m.	The licensee continued to investigate the 3A sequencer problem by testing the sequencer located at the simulator and by reviewing logic diagrams.
11/03/94	1:24 p.m.	The licensee concluded that a reportability condition existed and notified the NRC pursuant to 10 CFR 50.72(b)(1)(ii)(B) for Unit 3 being outside the design basis with the 3A and 3B HHSI pumps inoperable and the 4A HHSI pump administratively inoperable.
11/03/95	3:30 p.m.	The licensee determined that all four sequencers were inoperable while they were in the automatic or manual test modes.
11/03/94	3:45 p.m.	The licensee completed actions to remove all four sequencers from the automatic test mode thus restoring operability of the sequencers.
11/03/94	4:09 p.m.	The licensee notified the NRC pursuant to 10 CFR 50.72(b)(1)(ii)(B) for being outside the design basis with the 3A, 3B, 4A, and 4B emergency load sequencers inoperable.
11/04/94 to 11/07/94		The licensee conducted training at the plant simulator to evaluate crews' ability to respond to LOOP and/or LOCA scenarios with HHSI in pull-to-lock and with inoperable sequencers. The licensee also performed testing on the training center sequencer.
11/04/94		The LOOP/LOCA portion of train A safeguards was successfully completed.

Date(s) (Continued)	Time(s)	Event(s)
11/04/94		The PNSC approved 10 CFR 50.59 safety evaluation JPN-PTN-SEEP-94-041 for continued operation with sequencers out of the automatic test mode.
11/05/94		Train B safeguards testing was successfully completed.
11/07/94		The PNSC approved the evaluation (JPN-PTN-SEEP-94-043) regarding sequencer verification and validation with the test mode off.
11/07/94		HPES completed a root cause review of the HHSI pumps in pull-to-lock event.
11/09/94		The PNSC conducted a review and concluded that a substantial safety hazard existed per 10 CFR Part 21 (JPN-PTN-SENP-94-042).
11/10/94		The licensee issued LERs 50-250/94-004 and 50-250/94-005.
11/14/94		The licensee implemented TSA No. 3-94-24-17 on sequencer alarm circuits to remove the continuously lit annunciator in the control room.
11/15/94		United Controls, Inc. (the sequencer vendor) made a 10 CFR Part 21 report regarding this design error.
11/17/94		The licensee approved safety evaluation (JPN-PTN-SENP-94-045) to defer the monthly manual testing on sequencer.

8.3 Discussion

8.3.1 3A and 3B HHSI pumps inoperable for Unit 3

Unit 4 train A safeguards testing commenced on November 2, 1994. The LOOP and SI portions of the safeguards test were successfully completed. Following completion of the SI portion of the safeguards test; the 3A, 3B, 4A, and 4B HHSI pumps' control switches were verified to be in automatic. On November 3, 1994,

at approximately 8:35 a.m., during the LOOP/LOCA portion of the safeguards test, the 3A HHSI pump failed to start as required. The 3B and the 4A HHSI pumps started as required. The 4B HHSI pump does not start on a 4A train initiation.

The failure of the 3A HHSI pump to start as required caused the licensee to focus on determining the cause of the failure. However, the safeguards test was not affected, and the licensee continued with the test procedure. The safeguards test director noted the 3A HHSI pump failure as a deficiency and proceeded with the test. As part of recovery following the LOOP/LOCA test step 7.4.26 of the safeguards test required the 3A and 3B HHSI pumps and the 4A CS pump to be stopped. At this point, the test director apparently inadvertently directed the RO to place the 3A and 3B HHSI pumps and the 4A CS pump in the pull-to-lock position.

The Unit 4 RO placed the 3A and 3B HHSI pump, and the 4A CS pump switches in the pull-to-lock position. This caused two annunciators on both the Unit 3 and 4 sides of the control rooms to alarm indicating that the 3A and 3B HHSI pumps had tripped. The annunciators were acknowledged by each units' RO. The annunciator light remained illuminated as the condition continued to exist. At this point, the 4B HHSI pump was operable for Unit 3. The licensee considered the 4A HHSI pump administratively inoperable due to test equipment attachments. However, the 4A HHSI pump was available and had automatically started during the test. With the 4A HHSI pump administratively inoperable and with the 3A and the 3B HHSI pumps' control switches in the pull-to-lock position, Unit 3 was in a condition not allowed by Technical Specification 3.5.2 and was, therefore, in Technical Specification 3.0.3 LCO. This condition was not recognized by the operators on Unit 4 including the SRO and the RO involved in the test or by the RO and ANPS on Unit 3. The annunciators on Unit 3, which indicated that 3A and 3B HHSI pumps were tripped, were noted by the Unit 3 ANPS at a later period. However, the ANPS failed to recognize that Unit 3 was in a condition prohibited by technical specifications. The Unit 3 RO and ANPS assumed and accepted that the annunciators were related to the ongoing safeguards testing on Unit 4. At approximately 10:00 a.m., a shift turnover occurred for the Unit 3 ANPS, the Unit 4 ANPS, and the NPS. The oncoming Unit 3 ANPS and the outgoing Unit 3 ANPS discussed the illuminated annunciators. Again, the oncoming Unit 3 ANPS accepted the condition as being normal due to the ongoing Unit 4 safeguards test.

The oncoming NPS also walked down the control room boards and apparently noted at least one of the HHSI pumps in a pull-to-lock position. However, the NPS did not question the condition. The majority of the Unit 3 control room focus was on the 3A sequencer failure, and an effort was under way to plan the type and method of troubleshooting. A plan was devised by the licensee to troubleshoot the 3A sequencer. A manual test was successfully conducted, and the licensee planned to insert an SI signal to the 3A sequencer and to verify the starting of the 3A HHSI pump. A PWO was originated, and I&C personnel went to the control room to get permission to begin the troubleshooting. In anticipation of the planned I&C troubleshooting and of the need to have the 3A HHSI pump available during the 3A sequencer troubleshooting, an RO on Unit 4 noted that both the 3A and 3B HHSI pumps were in pull-to-lock. The RO notified the Unit 4 ANPS that the 3A HHSI pump would have to be taken out of pull-to-lock for I&C troubleshooting. The Unit 4 ANPS gave permission to take the 3A HHSI pump switch to the automatic position, and the switch was taken out of the pull-to-lock position at approximately 11:45 a.m.

The Unit 4 ANPS informed the NPS that the 3A HHSI pump was now out of pull-to-lock. The operations supervisor, who was in the vicinity, overheard that the 3A HHSI pump had been in the pull-to-lock position. He immediately questioned the reason the pump had been in pull-to-lock and walked over to the Unit 4 vertical panel board and noted that the 3B HHSI pump was also in pull-to-lock. He then directed that the 3B HHSI pump be taken out of pull-to-lock. The 3B HHSI pump was taken out of pull-to-lock at approximately 11:45 a.m.

By this time, the HHSI pumps' condition and related operations error was recognized. Licensing and the NRC resident inspectors were notified of the condition that Unit 3 was in from approximately 9:06 a.m. to 11:45 a.m. Licensing, operations, and plant management review concluded that a reportability condition existed. Consequently, at 1:24 p.m. on November 3, 1994, a notification to the NRC was made pursuant to 10 CFR 50.72(b)(1)(ii)(B) due to Unit 3 being outside of its design basis with the 3A and 3B HHSI pumps in the pull-to-lock position and the 4A HHSI pump administratively inoperable.

8.3.2 Emergency Load Sequencer Logic Defects

On November 3, 1994 during the LOOP/LOCA portion of safeguards testing on Unit 4, the 3A HHSI pump failed to start. The failure was attributed to a design defect in the software/logic of the 3A emergency load sequencer. It was later identified that the design defect also existed on the other three sequencers. A similar incident had occurred in May 1994 during which the 4A HHSI pump had failed to start upon receipt of an inadvertent SI signal on Unit 3. The SI signal was generated during restoration of the safeguards racks. The licensee was not able to determine the cause of the failure at that time.

The sequencers were placed in service in September 1991 and October 1991 on Units 3 and 4, respectively, following testing, validation, and verification. The sequencers were designed to perform load stripping and the sequential starting and reloading of necessary equipment without overloading the emergency buses or the emergency diesel generators on degraded voltage conditions on 4KV or 480V buses. The following is a list of the five bus stripping scenarios and eleven load sequencing scenarios:

- Bus Stripping

  1. bus clearing relays
  2. 480V degraded voltage
  3. 480V degraded voltage with SI present
  4. 4KV under voltage
  5. SI with EDG on an isolated bus

- Load Sequencing

  1. LOOP
  2. LOOP/LOCA
  3. LOOP/LOCA other unit
  4. LOCA
  5. LOCA other unit
  6. LOOP/LOCA with concurrent HHCP
  7. LOCA with concurrent HHCP
  8. LOOP/LOCA with HHCP before 13 seconds
  9. LOCA with HHCP before 13 seconds
  10. LOOP/LOCA with HHCP after 13 seconds
  11. LOCA with HHCP after 13 seconds

The sequencers were designed for operation in the automatic test mode, a manual test mode, or with the test mode in OFF. Automatic testing of the sequencer involved continuously testing the input cards, output cards, output relay coils, and exercising the program logic without activating any ESF equipment. These tests were designed to be performed for an hour duration for each of the above sixteen stripping/bus clearing and sequencing scenarios. Therefore, the automatic testing cycle was repeated every sixteen hours. Automatic testing was performed with the test selector switch in the AUTO position. Manual testing could be performed by taking the test selector switch to the MANUAL position and individually testing the above mentioned sixteen load stripping and sequencing scenarios. Manual testing was more extensive because it challenged the output relays. Like the automatic test mode, the manual test did not result in the actual start of any ESF equipment. The manual test was being performed on all four sequencers on a monthly basis. None of this manual or automatic testing was required by technical specifications. A design requirement included that when the sequencer was in the automatic or manual test mode any actuation signal would stop the test. All sequencer counters and timers would be reset, and the sequencer would respond as required without any significant time delay.

Following the failure of the 3A HHSI pump to start during safeguards testing simulating a LOOP/LOCA on Unit 4, the licensee performed analysis and tests on the sequencer located in the

training center to recreate the failure and determine the cause. The licensee determined that a software logic error existed when the sequencer was in any five load sequencing steps of the total sixteen testing modes as follows:

- Step 2, LOOP/LOCA
- Step 3, LOOP/LOCA other unit
- Step 6, LOOP/LOCA with concurrent HHCP
- Step 8, LOOP/LOCA with HHCP before 13 seconds
- Step 10, LOOP/LOCA with HHCP after 13 seconds

The logic error was such that if a valid LOCA only signal were received fifteen seconds or later into one of the five above mentioned test steps, the test signal cleared as intended. However, an inhibit signal was maintained by means of a latching (seal-in) logic. This latching logic was established by the test signal but continued to be maintained by the process input signal if it arrived prior to removal of the test signal. This logic error was introduced during initial design. A design requirement was the capability to allow operators to reset SI without stopping necessary ESF equipment following a LOCA/LOOP event. This was accomplished by an inhibit function via a latching logic. The inhibit function was needed only for the LOOP portion of the logic. This inhibit would preclude stripping of the ESF loads and reload only LOOP loads following SI reset, thus maintaining LOCA loads in service. It was during this design of the SI reset capability that the logic error was introduced affecting operability of the sequencer during portions of automatic or manual testing. The logic error was that the designer inadvertently included the inhibit function also for the LOCA only portion of the logic. Thus, if the sequencer were in load sequencing steps 2, 6, 8, or 10 of the above vulnerable test functions and a LOCA only signal were received, the sequencer would not start necessary ESF equipment. This equipment included HHSI, CS, RHR, CCW, and ICW pumps; the electrical load center breakers; and the ECC and ECF units.

During the LOOP/LOCA other unit scenario (load sequencing step 3), the sequencer would be inhibited from responding to a valid SI signal on the opposite unit. During the other four vulnerable test scenarios, the sequencer would be inhibited from responding to a valid SI signal on the same train of the same unit.

Following the installation of the sequencers in September and October of 1991 on Units 3 and 4, respectively, the sequencers had experienced some failures of the automatic test output card relays. These December 1991 failures had occurred because the frequency of automatic test cycle was every three minutes for each of the sixteen scenarios. This frequent testing was wearing out certain output relays. A safety evaluation was performed allowing the sequencers to be operated with the test mode in the OFF position. Subsequently, the licensee performed a modification and

changed the automatic test frequency from three minutes to every hour. The sequencers were returned to the automatic test mode in November 1992 and May 1993 for Units 3 and 4, respectively. However, this modification did not affect the already existing inhibit logic design flaw. The problem with the inhibit logic was present even with the automatic test frequency of three minutes. The licensee updated the previous evaluation and reconfirmed that the sequencers would perform as intended with the test mode in the OFF position. In this mode, the sequencer was not subjected to the process logic inhibits; therefore, precluding the interactions which compromised the sequencer's ability to start necessary ESF equipment. The updated safety evaluation (JPN-PTN-SEEP-94-041) was approved PNSC on November 4, 1994.

An engineering evaluation (JPN-PTN-SEEP-94-043) was also performed to document the review of the existing verification and validation of the sequencer software. This evaluation reviewed the verification and validation with the test switch in the OFF position. The evaluation concluded that all sequencer design bases and safety functions had been adequately tested for the sequencer in the test OFF mode. Therefore, the sequencer would function as required. In addition, during this review of the validation and verification that had been performed, the licensee concluded that not all stripping and loading sequences of the automatic and manual testing logic were tested either during the factory verification and validation or during the performance of the preoperational test procedures.

The licensee also performed an evaluation (JPN-PTN-SENP-94-042) which determined that the sequencer logic defect represented a major degradation of safety-related equipment. This conclusion was based on an assumption of a large break LOCA requiring safety injection with no loss of offsite power and the software design error in the test circuitry resulting in all four sequencers failing to load the sequencer controlled ESF equipment. The analysis determined that even with operator action, there was a potential for core damage. Based on this, the licensee determined that the sequencer software design error represented a defect that could have created a substantial safety hazard. Consequently, the licensee determined that the incident was reportable under 10 CFR Part 21. This was documented in LER 50-250/94-005.

8.4 Licensee Actions

8.4.1 3A and 3B HHSI Pumps Inoperable

Relative to inoperability of the 3A and the 3B HHSI pumps when operators inadvertently placed the Unit 4 control room switches in pull-to-lock, the licensee performed a line management review and an independent HPES review.

These reviews concluded that the root cause was personnel error due to the following:

- inaccurate verbal communication from the test director (SRO) to the RO,

- failure to perform self-checking, and

- less than adequate coverage of Unit 3 equipment and effects during the pre-job briefing.

Further, the licensee identified possible contributing causes which included:

- poor work practices,

- poor oversight,

- procedural inadequacy, and

- training deficiencies.

The licensee's corrective actions included the following items:

- immediately returned the 3A and 3B HHSI control switches to automatic;

- made a 10 CFR 50.72 notification;

- modified the OSP to include specific words regarding the HHSI pump switch automatic positions and independent verifications;

- briefed each of the operating crews on the event with focus on self checking, procedure compliance, maintaining a questioning attitude, and importance of shared equipment relative to the safe operation of Unit 3;

- caution tagged common (shared) equipment control switches on the Unit 4 boards;

- performed an independent human performance root cause investigation;

- designated an independent test oversight supervisor with no concurrent duties;

- conducted training including simulator scenarios for LOCA events with HHSI pumps in pull-to-lock; and

- submitted LER 50-250/94-004 regarding this event.

8.4.2 Emergency Load Sequencer Logic Defects

Relative to the potential vulnerability of the Unit 3 and 4 emergency load sequencers while in the automatic test mode, the licensee implemented the following corrective actions:

- immediately declared all four sequencers inoperable, placed the test selector switches to off, and controlled them with a clearance and re-established operability per the December 1991 evaluation;
- made a 10 CFR 50.72 notification;
- verified operability of the sequencers with the test mode off with an approved and revised safety evaluation;
- performed functional testing of the sequencers using the training sequencer and verified operability with the test mode off;
- reviewed the originally conducted validation and verification test process and issued an engineering evaluation which concluded the sequencer safety functions were satisfactory with the test mode off;
- performed visual inspections of the local sequencer panels to ensure operability at 8 and 24-hour intervals and modified operator round sheets and logs appropriately;
- performed an evaluation relative to safety significance and 10 CFR Part 21 applicability;
- submitted LER 50-250/94-005 regarding this event;
- issued a training bulletin (No. 520) regarding the sequencers, actions, and other items and briefed each crew;
- notified the software vendor;
- retained a third party to perform an assessment of existing sequencers and software designs, test programs, and relative engineering design procedures;
- implemented a TSA to remove continuously lit annunciator alarm caused by test switch in off;
- performed control room simulator exercises for all crews to assess operator response to sequencer failure LOOP and/or LOCA scenarios; and
- performed a core damage risk assessment calculation for inoperable sequencers.

8.5 NRC Review and Conclusion

8.5.1 3A and 3B HHSI Pumps Inoperable

The inspectors monitored portions of the safeguards testing activities. (Refer to section 5.2.3 for additional information.) When the 3A HHSI pump failed to start, the inspectors followed licensee-related activities including observing the 3A sequencer manual test, evaluating the licensee's operability assessment, and monitoring the licensee's troubleshooting activities. At about noon on November 3, 1994, the operations supervisor notified the inspectors of the issues related to the 3A and 3B HHSI pump switches having been in pull-to-lock.

The inspectors reviewed plant conditions, operator logs, test results, computer printouts, QA notes, and other related documentation. Based on this, the 3A and 3B HHSI pumps were confirmed to be out-of-service (e.g., in pull-to-lock) for 2 hours and 39 minutes. The inspectors reviewed Technical Specifications 3.5.2 and 3.0.3. Although no violations of the action statements were noted, the inspectors expressed concern regarding the inoperability of redundant safety equipment. Further, although the 4B HHSI pump was the only operable pump; the 4A pump was available, and the 3A and 3B pumps were also available once the control switches were returned to automatic.

The inspectors interviewed selected licensed operators involved in the test and unit responsibilities. The ROs and SROs including the Unit 3 and 4 RCOs and ANPSs and the NPS all noted the condition associated with the 3A and 3B HHSI pumps, and they concluded that it was satisfactory due to the Unit 4 test in progress. The inspectors concluded that most of the control room licensed operators were considering only the Unit 4 test conditions and not the effect on Unit 3.

The inspectors also witnessed control room simulator exercises on Unit 3 which were run with the 3A and 3B HHSI pumps in pull-to-lock from the Unit 4 switches. In all cases, operators followed the EOPs (3-EOP-E-0, Reactor Trip or Safety Inspection, and 3-EOP-E-1, Loss of Reactor or Secondary Coolant). Immediate action steps 4 and 8 of procedure 3-EOP-E-0 required operators to verify SI actuation and the running of HHSI pumps. These steps were all done within 3 minutes. The inspectors also verified that previous training conducted in 1994 during the requalification cycle included sequencer failure scenarios. Operators appropriately responded to these exercises by manually initiating safety equipment.

The inspectors reviewed an independent root cause investigation of the event performed by the HPES coordinator. Event and causal factor analysis techniques and barrier analysis techniques were used. Root causes and contributing causes were identified, and

corrective actions were recommended. (Refer to section 8.4.1 for additional information.) The licensee initiated immediate corrective actions which the inspectors independently verified. The inspectors determined that this independent root cause review was noteworthy.

The inspectors reviewed overtime records for all operators involved during the dayshift on Thursday, November 3, 1994. At Turkey Point, Thursday is referred to a "break shift" day because there is no scheduled day shift. Day shift rotation ends on Wednesday and Friday begins another. Thus, on Thursday, day shift operator staffing was manned with the use of overtime or using operators not currently on shift rotation. The inspectors noted that on Thursday, November 3, 1994, no operator exceeded any regulatory limits; however, most operators were working scheduled overtime. Further, the inspectors concluded that although operating errors could occur during high overtime periods, none occurred during this event caused by potentially tired operators.

The licensee considered the integrated safeguards test as an infrequently conducted evolution. Therefore, the requirements of procedure 0-ADM-217, Conduct of Infrequently Performed Test or Evolutions, were applied. A test manager and test director were appointed. The test director was involved in test implementation. The NPS was designated as the test manager. Although procedure 0-ADM-217 allowed this, the inspectors concluded that an individual with no concurrent responsibilities could have better assumed the duties of a test manager. The licensee stated that it would review its policy on this matter.

Technical Specification 6.8.1 requires that written procedures be established, implemented, and maintained covering the activities referenced in Appendix A or Regulatory Guide 1.33, revision 2, February 1978. This included surveillance test procedures. Surveillance test procedure 4-OSP-203.1, Train A Engineered Safeguards Integrated Test, step 7.4.26, required the control switches for the 3A and 3B HHSI pumps to be placed in STOP (spring return to AUTO). On November 3, 1994, at or about 9:06 a.m. the 3A and 3B HHSI pumps were placed in PULL-TO-STOP (pull-to lock) rather than STOP (spring return to AUTO). This action caused the pumps to be unavailable for automatic starting on a Unit 3 safety injection signal for about 2 hours and 39 minutes. During this time, automatic safety injection for Unit 3 was available from the 4A and 4B high head safety injection pumps. Failure to follow procedure 4-OSP-203.1 is a violation of Technical Specification 6.8.1, and it will be tracked as VIO 50-250,251/94-23-02, Failure to Follow Procedure Resulting in Inoperability of Two HHSI Pumps.

The inspectors reviewed and verified the corrective actions stated in both LER 50-250/94-004 and section 8.4.1 of this report. The inspectors concluded that the corrective actions were adequate;

and based on this review, the LER and violation are considered closed.

8.5.2 Emergency Load Sequencer Logic Defects

The inspectors monitored licensee actions and verified the corrective actions documented in section 8.4.2. When notified of sequencer vulnerability, the inspectors verified that four test switches (one for each sequencer) were tagged in the off position. The inspectors questioned the basis for sequencer operability in this mode. The licensee referenced a 1991 evaluation, a subsequent NRC review, and Units 3 and 4 operation for 12 months and 18 months, respectively, with the test mode off. Further, the licensee updated that 1991 safety evaluation (JPN-PTN-SEEP-94-041), and PNSC approved it on November 4, 1994.

The inspectors reviewed this safety evaluation, the engineering evaluation related to the sequencer validation and verification test programs with the test in the mode off position, the evaluation relative to the safety significance and 10 CFR Part 21 assessments, and the safety evaluation relative to manual testing frequency. The inspectors also attended the PNSC meetings which reviewed and approved these evaluations and LER 50-250/94-005. These documents appeared to be complete, well written, and they appropriately addressed the safety and operability issues.

The inspectors reviewed the referenced training bulletin, related training documentation, loss of sequencer simulator scenarios, and results. The licensee concluded that the operators appropriately responded per the EOPs to sequencer failure scenarios. Operators were able to respond to scenarios including LOOP, LOCA and LOOP/LOCA events. Thus, operators were successful in manually starting safety equipment. The inspectors confirmed this noting strong EOP implementation and overall performance.

The inspectors reviewed the licensee's PSA-related calculation (PTN-BFJR-94-016) for a failure of the sequencers during various LOCA scenarios. The licensee used its June 1991 submitted IPE and the following assumptions:

- all four sequencers fail;
- operator actions were taken to strip electrical buses and manually load emergency equipment;
- core melt times were consistent with current codes;
- simulator information and EOP steps to start safety equipment (including ECCS) were reviewed; and
- operator failure rate was assumed to vary between 6% for a large LOCA and 0.4% for a small LOCA.

The licensee's calculation determined that the increase in core damage frequency was 2.1 E-6 or an increase of 3.2% for the facility.

The inspectors reviewed the sequencer logic diagrams (5613, 4-E-27B series and 5610-T-L1 (various sheets)) and confirmed that during an actual SI (LOCA) event with the automatic or manual test mode in the LOOP/LOCA function (e.g., load sequencer test step Nos. 2, 3, 6, 8, or 10), the emergency load sequencer would fail to automatically start safety equipment. Further, the inspectors observed this design deficiency during spare sequencer testing at the simulator. The inspectors also noted that with the test mode off, the safety function of the sequencer appeared to respond appropriately.

Another plant experienced a sequencer automatic test failure while shutdown, and identified a related sequencer vulnerability in July 1992. The NRC issued Information Notice 93-11 in February 1993. The licensee responded to this notice in conjunction with a response to an INPO significant event report (1-93). This response focused on the shutdown plant events/issues, and these issues were closed in January 1994. The inspectors reviewed the referenced documents including the licensee's response. The inspectors concluded that the licensee did not address the automatic test vulnerability issue. This was discussed with the licensee. At the close of the period, the licensee had re-opened the NRC Information Notice and intends to evaluate any future actions.

10 CFR Part 50, Appendix B, Criterion III, Design Control, required, in part, that design changes be subject to design control measures which provide for verifying or checking the adequacy of design by performance reviews or by the performance of a suitable test program. Design change PC/M No. 87-264 added sequencers 3A, 3B, 4A, and 4B to the Unit 3 and 4 design during the dual unit outage (November 1990 through September 1991). PC/M No. 87-264 design reviews and the verification/validation and preoperational test programs failed to identify a vulnerability in the 3A, 3B, 4A, and 4B sequencers. This vulnerability existed for the sequencers while in the automatic test mode for test sequence Nos. 2, 3, 6, 8, and 10 such that when an actual LOCA signal was received, the sequencers would malfunction. The licensee identified this sequencer vulnerability as a condition outside the design basis on November 3, 1994. The condition existed from September through November 1991 and December 1992 through November 1994 on Unit 3 and from October 1991 through November 1991 and May 1993 through November 1994 on Unit 4. During these periods, all four sequencers (3A and 3B for Unit 3 and 4A and 4B for Unit 4) were vulnerable such that, at times, they would not have automatically started safety equipment in response to accident signals. This failure to adhere to the requirements of 10 CFR Part 50, Appendix B, Criterion III, is an apparent violation and

will be tracked as EEI 50-250,251/94-23-03, Failure to Meet 10 CFR Part 50, Appendix B, Criterion III, Design Control, Resulting in Inoperable Emergency Load Sequencers. LER 50-250/94-005 is considered closed as corrective actions will be tracked as part of the apparent violation open item.

9.0 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 November 28, 1994. (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
50-250,251/94-23-01	(Closed) NCV - Snubber Surveillance Program Problems (section 5.2.7)
50-250,251/94-23-02	(Closed) VIO - Failure to Follow Procedure Resulting in Inoperability of Two HHSI Pumps (section 8.5.1)
50-250,251/94-23-03	(Opened) EEI - Failure to Meet 10 CFR Part 50, Appendix B, Criterion III, Design Control, Resulting in Inoperable Emergency Load Sequencers (section 8.5.2)

Additionally, the following previous items were discussed:

Item Number	Status, Description, and Reference
50-250,251/94-05-03	(Closed) URI - PORV Seat Leakage (section 5.2.8)
50-250/94-004	(Closed) LER - Unit 3 Outside Design Review Due to 2 of 3 Required HHSI Pumps Inoperable (section 8.5.1)
50-250/94-005	(Closed) LER - Safeguards Sequencer Automatic Test Function Places Both Units in a Condition Outside the Design Basis (section 8.5.2)

10.0 Acronyms and Abbreviations

AC	Alternating Current
ADM	Administrative (Procedure)
ALARA	As-Low-As-Reasonably-Achievable
amp	Ampere

AMSAC	ATWS Mitigation System Actuation Circuitry
ANPS	Assistant Nuclear Plant Supervisor
AP	Administrative Procedure
ASB	Auto-Stop Backup
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
BOL	Beginning of Life
cc	Cubic Centimeter
CCW	Component Cooling Water
CFR	Code of Federal Regulations
cm	Centimeter
CNRB	Company Nuclear Review Board
CRDM	Control Rod Drive Mechanism
CS	Containment Spray
CTRAC	Commitment Tracking
CV	Control Valve
DB	Design Basis
DC	Direct Current
ECC	Emergency Containment Cooler
ECCS	Emergency Core Cooling System
ECF	Emergency Containment Filter
EDG	Emergency Diesel Generator
EEI	Escalated Enforcement Item
EOP	Emergency Operating Procedure
ERT	Event Response Team
ESF	Engineered Safeguards Feature
°F	Degrees Fahrenheit
FPL	Florida Power and Light
GOP	General Operating Procedure
gpm	Gallons Per Minute
HDT	Heater Drain Tank
HHCP	High High Containment Pressure
HHSI	High Head Safety Injection
HPES	Human Performance Evaluation System
I&C	Instrumentation and Control
ICW	Intake Cooling Water
INPO	Institute for Nuclear Power Operations
IPE	Individual Plant Evaluation
ISI	Inservice Inspection
JPN	Juno Project Nuclear (Nuclear Engineering)
KV	Kilovolt
KVAR	Kilovolt Amperes Reactive
KW	Kilowatt
La	Containment Allowed Leak Rate
LC	Level Controller
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss-of-Coolant Accident
LOOP	Loss of Offsite Power
mph	Miles Per Hour
mRem	Milliroentgen Equivalent Man
MWe	Megawatts Electric

NCV	Non-Cited Violation
NIS	Nuclear Instrumentation System
NPO	Nuclear Plant Operator
NPS	Nuclear Plant Supervisor
NRC	Nuclear Regulatory Commission
NSD	Nuclear Safety Division
NWE	Nuclear Watch Engineer
ONOP	Off-Normal Operating Procedure
OP	Operating Procedure
OSHA	Occupational Health and Safety Administration
OSP	Operations Surveillance Procedure
OTSC	On-the-Spot Change
PC	Power Cabinet
PC/M	Plant Change/Modification
PCV	Pressure Control Valve
PMAI	Plant Manager Action Item
PMI	Preventive Maintenance - I&C
PMM	Preventive Maintenance - Mechanical
PNSC	Plant Nuclear Safety Committee
POP	Pre-Operational Procedure
PORV	Power-Operated Relief Valve
PS	Power Supply
PS	Pressure Switch
PSA	Probabilistic Safety Assessment
psig	Pounds Per Square Inch Gauge
PTN	Project Turkey Nuclear
PWO	Plant Work Order
QA	Quality Assurance
QAO	Quality Assurance Organization
QC	Quality Control
RCO	Reactor Control Operator
RCS	Reactor Coolant System
Rem	Roentgen Equivalent Man
RHR	Residual Heat Removal
RPI	Rod Position Indication
RPS	Reactor Protection System
RO	Reactor Operator
RTD	Resistance Temperature Detector
RWST	Refueling Water Storage Tank
RV	Relief Valve
SEEP	Safety Evaluation Electrical - Plant
SENP	Safety Evaluation Nuclear - Plant
SI	Safety Injection
SRO	Senior Reactor Operator
T	Temperature
TB	Technical Bulletin
TP	Temporary Procedure
TSA	Temporary System Alteration
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
V	Volt
VIO	Violation
WO	Work Order