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

Report Nos.: 50-250/93-24 and 50-251/93-24

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: September 26 through October 30, 1993

Inspectors: A.R. Long for — 11/18/93
T. P. Johnson, Senior Resident Inspector — Date Signed

A R Long for — 11/18/93
B. B. Desai, Resident Inspector — Date Signed

A.R. Long for — 11/18/93
L. Trocine, Resident Inspector — Date Signed

Approved by: M V Sinkule for — 11/19/93
K. D. Landis, Chief — Date Signed
Reactor Projects Section 2B
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection involved direct inspection at the site and at the licensee's Juno Beach office in the areas of surveillance observations, maintenance observations, engineered safety features walkdowns, operational safety, plant events, and management meetings. Backshift inspections were performed in accordance with NRC policy.

Results:

Within the scope of this inspection, the inspectors determined that the licensee generally demonstrated satisfactory performance to ensure safe plant operations. A violation of operating and administrative procedure was identified. A reactor control operator failed to properly monitor and log a reactivity addition evolution. In addition, the licensee, through self assessment, took prompt action to correct a non-cited violation involving lifting the wrong electrical leads and related independent verification failure by Instrumentation and Control technicians.

This inspection resulted in the following findings:

- Non-Cited Violation 50-250,251/93-24-01, Wrong Leads Lifted/Independent Verification Failure (section 7.2.4).

- Violation 50-250,251/93-24-02, Inadvertent Dilution Event (section 9.2.6).

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

Plant Operations

An unresolved item regarding operator rounds and falsification of records was elevated to a violation with no severity level and was closed (section 4.2.2). The licensee's actions with regard to the Unit 3 reactor trip signal while subcritical and during pressurizer manway repair were conservative and appropriate (sections 3.1, 6.2.1, 7.2.1, 9.2.1, and 10.2.3). The Unit 3 short notice outage was well planned, and the subsequent unit startup activities were conducted in a professional manner (section 9.2.3). The auxiliary feedwater and safety injection systems were appropriately aligned for automatic actuations (section 8.2.1). However, a weakness was noted in that the auxiliary feedwater pump was not declared inoperable during the time that the oil filter rig was aligned to the oil tank (section 7.2.5). Shift turnover meetings and relief activities were effective in communicating information and plant status to the oncoming operating crews. However, minor weaknesses were noted relative to the professional conduct of the meetings (section 9.2.2). The control of operator aids and information tags was appropriate; however, minor weaknesses were noted relative to the age of these items and with tag duplication (section 9.2.4). An inadvertent dilution event on Unit 3 was caused by a weakness in the area of conduct of operations. A violation for failure to follow operating and administrative procedures associated with this reactivity addition was issued (section 9.2.6). A weakness associated with the Unit 3 feedwater isolation that occurred while in Mode 4 was noted in that the incident could have easily been prevented by securing the standby steam generator feedwater pump to terminate the steam generator level increase (section 10.2.2).

Maintenance and Surveillance

Observed surveillance tests were conducted professionally, and these tests demonstrated equipment operability (section 6.1). The licensee's actions regarding root cause and corrective actions for the Unit 3 pressurizer manway leak were effective (section 7.2.1). The licensee's leak sealant practices appeared to be appropriate (section 7.2.2), and the licensee's efforts with regard to the repair or the 4A feedwater pump discharge check valve were both efficient and effective (sections 3.2 and 7.2.3). Weaknesses relative to Instrumentation and Control personnel lifting the wrong electrical leads and related independent verification failure were noted relative to main steam isolation valve

troubleshooting, and were classified as a non-cited violation (section 7.2.4).

Engineering and Technical Support

Engineering support for the Unit 3 pressurizer manway repair and containment inspections was strong (section 7.2.1). Engineering responsiveness to several questions asked by the inspectors during the auxiliary feedwater system walkdown was thorough and aggressive (section 8.2.1). An engineering meeting conducted at the licensee's corporate office in Juno Beach, Florida, was beneficial in keeping the Nuclear Regulatory Commission informed of licensee initiatives and aware of the status of ongoing enhancements (section 11.2.2).

Plant Support (Radiation Controls, Emergency Preparedness, Security, Chemistry, Fire Protection, Fitness For Duty, and Housekeeping Controls)

The licensee appropriately responded to a previously identified violation regarding a failure to follow procedure during resin transfer operations (section 4.2.1). The licensee effectively controlled containment entries at power and while shutdown (section 9.2.1). The emergency notification phone (FTS-2000) was out of service for several days (section 9.2.5). The licensee effectively conducted and critiqued an emergency plan drill (section 9.2.7), and the licensee appropriately followed up on two contamination events that occurred during the Unit 3 short notice outage (section 10.2.1).

The inspectors reviewed the following outstanding items:

- (Closed) Violation 50-250,251/92-16-01, Failure to Follow a Procedure Resulting in Spill of Flush Water and Residual Spent Resin in the Radwaste Building (section 4.2.1).

- (Closed) **Unresolved Item 50-250,251/92-28-05, Falsification of Plant Records (section 4.2.2).

- (Closed) Licensee Event Report 50-250/93-006, Reactor Trip During Shutdown Due to Excore Nuclear Instrument Source Range Failure (section 5.2.1).

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

REPORT DETAILS

1.0 Persons Contacted

1.1 Licensee Employees

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

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

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

K. D. Landis, Chief, Reactor Projects Section 2B, Division of Reactor Projects, Region II
E. W. Merschoff, Director, Division of Reactor Projects, Region II

M. V. Sinkule, Chief, Reactor Projects Branch 2, Division of Reactor Projects, Region II

* Attended exit interview on October 29, 1993

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

2.0 Other NRC Inspections Performed During This Period

Report No.	Dates	Area Inspected
50-250,251/93-23	October 15, 1993	Speakout Program Inspection Continuation
50-250,251/93-25	October 25-29, 1993	MOV Inspection

3.0 Plant Status

3.1 Unit 3

At the beginning of this reporting period, Unit 3 was operating at 100% power and had been on line since January 20, 1993. The following evolutions occurred on this unit during this assessment period:

- At 7:42 p.m. on September 30, 1993, the licensee commenced a Unit 3 shutdown due to the identification of an RCS leak on the pressurizer manway, and the unit was taken off line at 9:49 p.m. on the same day. (Refer to sections 6.2.1, 7.2.1, and 9.2.1 for additional information.)

- At 10:05 p.m. on September 30, 1993, Unit 3 experienced a sub-critical reactor trip when the source range detectors were energized and N31 failed high. (Refer to section 10.2.3 for additional information.) Mode 5 was entered at 9:15 p.m. on October 1, 1993.

- At 6:15 p.m. on October 5, 1993, the licensee commenced a heatup on Unit 3. Reactor startup was commenced at 8:30 p.m. on October 6, 1993, and criticality was achieved at 9:02 p.m. Unit 3 was placed back on line at 3:44 a.m. on October 7, 1993, and 100% reactor power was re-achieved at 2:30 a.m. on October 8, 1993. (Refer to section 9.2.3 for additional information.)

- At 5:55 p.m. on October 11, 1993, the licensee commenced a Unit 3 load reduction to 85% reactor power in order to facilitate the performance of flux mapping. The unit was returned to 100% reactor power at 3:50 a.m. on the following day.

- At 8:00 p.m. on October 18, 1993, the licensee commenced a Unit 3 shutdown to Mode 2 in order to facilitate the performance of work on a 3B MSIV DC ground and on the voltage regulator. (Refer to section 7.2.4 for additional information.) The licensee took the unit off line at 9:55 p.m. On October 20, 1993, Unit 3 was placed on line at 8:55 a.m., was stabilized at 30% reactor power for a chemistry hold at 9:20 a.m., and was returned to 100% reactor power at 11:30 p.m.

- At 9:10 p.m. on October 22, 1993, an inadvertent dilution event occurred due to operator error, and Tavg and reactor power both increased. (Refer to section 9.2.6 for additional information.)

3.2 Unit 4

At the beginning of this reporting period, Unit 4 was operating at 100% power and had been on line since August 17, 1993. The following evolutions occurred on this unit during this assessment period:

- At 9:15 a.m. on September 30, 1993, the licensee commenced a Unit 4 load reduction to 85% reactor power in order to facilitate the performance of flux mapping. The unit was returned to 100% reactor power at 5:20 p.m. on the same day.

- At 11:30 a.m. on October 12, 1993, the licensee commenced a Unit 4 load reduction to 40% reactor power to facilitate the performance of turbine valve testing, waterbox and TPCW heat exchanger cleaning, and steam generator feedwater pump discharge a check valve inspection and repair. Following the completion of the turbine valve testing, reactor power was stabilized at 55% at 7:00 p.m. on the same day. (Refer to section 7.2.3 for additional information.)

- At 10:10 p.m. on October 14, 1993, the licensee commenced power ascension on Unit 4, and 100% reactor power was re-achieved at 2:25 a.m. on the following day.

- At 9:45 p.m. on October 15, 1993, the licensee commenced a Unit 4 load reduction due to indication of condenser tube leakage in the 4B north waterbox. Reactor power was less than 45% at 10:46 p.m. and was stabilized at 60% at 4:45 a.m. on the following day. Following tube leak repairs, 100% reactor was re-achieved at 2:00 p.m. on October 18, 1993.

- At 1:50 a.m. on October 20, 1993, the licensee commenced a load reduction to 30% reactor power due to indications of a tube leak in the 4B north waterbox. Following isolation of the waterbox, reactor power was increased to 60% at 12:00

p.m. on the same day in order to facilitate repairs, and 100% reactor power was re-achieved at 2:45 p.m. on the following day.

4.0 Action on Previous Inspection Findings (92702, 92701)

4.1 Inspection Scope

A review was conducted of the following noncompliances to assure that corrective actions were adequately implemented and resulted in conformance with regulatory requirements. Verification of corrective action was achieved through record reviews, observation, and discussions with licensee personnel. Licensee correspondence was evaluated to ensure the responses were timely and corrective actions were implemented within the time periods specified in the reply.

4.2 Inspection Findings

4.2.1 (Closed) VIO 50-250,251/92-16-01, Failure to Follow a Procedure Resulting in a Spill of Flush Water and Residual Spent Resin in the Radwaste Building.

The licensee responded to this violation by letter dated September 15, 1992, and attributed this violation to personnel error. In lieu of connecting one hose from the fill/divert valve to the flush container fill head, operators mistakenly utilized two identical hoses which were loosely coiled together on the floor and appeared to be a single hose. One end of one hose was connected to the fill/divert valve, and one end of the other hose was connected to the flush container fill head. The licensee stated that the procedure was followed verbatim but that the operators did not verify the continuity of the hose for its entire length from the fill/divert valve to the flush container fill head.

As a result of this event, the licensee barricaded the area of the spill to prevent radioactive water from leaking out of the Radwaste Building. The licensee also erected a spill barrier at the truck bay door to prevent the spill from reaching the environment and placed a temporary, reusable, storm drain cover over the storm drain at the entrance to the truck bay. The spill barrier and the temporary storm drain cover were not challenged because the spill was successfully contained by the barricade around the spill area. The licensee subsequently suspended primary resin transfers to waste containers until an investigation and appropriate corrective steps could be completed. The licensee also recovered the contaminated area in the Radwaste Building, and counselled the individuals who made and verified the improper connections on the importance of the confirmation of the correct flow path. In addition, the licensee documented the cause of this

event and planned corrective actions in Condition Report No. 92-0097, Spent Primary Resin Spill.

The resin transfer evolution of July 9, 1992, was performed in accordance with plant procedure O-HPS-042.5, Transfer and Dewatering Bead Resin in RADLOK High Integrity Containers, and vendor procedure OM-049-WS, Operating Procedure for Pacific Nuclear/Waste Services Group Resin Drying (Dewatering) System at Florida Power and Light Company - Turkey Point. Prior to the performance of the next resin transfer, the licensee suspended utilization of vendor procedure OM-049-WS for resin transfer and replaced it (for utility use) with a revision to plant procedure O-HPS-042.5. However, plant procedure O-HPS-042.5 was eliminated in 1993 due to an equipment change, and procedure O-HPS-042.6, Resin Drying System Operations, was issued to cover the same activity. Procedure O-HPS-042.6 incorporated the following four requirements:

- The temporary hoses used for waste transfers are to be color-coded and uniquely identified with tags on each end that indicate the component to which that end of the hose is to be attached. Identical tags will be used to identify the system component to which the hose is to be attached.

- The step by step sign-offs and independent verifications will be completed at pertinent steps for equipment setup and operations.

- A procedural step requiring that a spill barrier be in place at the truck bay door and a drain cover be placed over the storm drain prior to transferring primary waste or spent resin to the waste containers was developed.

- Steps requiring verification of waste flow paths with primary waste water before transferring resin were also incorporated.

The HP Department also reviewed other HP procedures for applicability of the first two items listed above.

An October 16, 1992, NRC letter acknowledging the September 15, 1992, licensee response to the Notice of Violation documented the following additional corrective actions which had been or were planned to be taken:

- Curbs were installed across the Radwaste Building truck bay door floor and the floor threshold for the south personnel doorways to prevent outflow of fluid if another spill were to occur.

- Plant procedure O-PMM-061.1, Auxiliary Building Floor and Containment Building Roof Drains Inspection and Cleaning,

was revised to incorporate steps for the flushing of the drains in the Radwaste Building.

- In order to ensure the proper operation of the drains, the licensee suspended the performances of resin transfers until cleaning of the drain sumps was performed.

The licensee installed curbs in the roll-up doorway and south personnel doorways by August 21, 1993. In addition, the licensee completed floor drain preventive maintenance and testing on July 12, 1993, and the first post-spill resin transfer was successfully performed on July 16, 1993, when non-primary resin was transferred from the demineralizer bed in the south filling area through a Pacific fill head to a liner. Primary flush resin was successfully transferred from the spent resin storage tank to a high integrity container in the Radwaste Building on August 18, 1993.

This event was also documented in paragraph 7.6 of NRC Inspection Report No. 50-250,251/92-25 dated December 2, 1992. This issue remained open at that time because all of the corrective actions had not been fully implemented.

The inspectors reviewed Condition Report No. 92-0097, verified the performance of the corrective actions, and discussed these actions with the lead inspector for NRC Inspection Report No. 50-250,251/92-25. The inspectors also determined that the licensee's corrective actions were adequate. This item is closed.

4.2.2 (Closed) URI 50-250,251/92-28-05, Falsification of Plant Records.

The NRC issued a Notice of Violation dated October 15, 1993. This Notice did not have a severity level, nor did it require a response. Based on this, the URI is closed.

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

5.1 Inspection Scope

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

5.2 Inspection Findings

5.2.1 (Closed) LER 50-250/93-006, Reactor Trip During Shutdown Due to Excore Nuclear Instrument Source Random Failure.

This issue is discussed in section 10.2.3 of this report. The inspectors concluded that the LER was satisfactory; and therefore, this LER is closed.

5.2.2 Monthly Operating Report

The inspectors reviewed Unit 3 and 4 Monthly Operating Report for September 1993. This report was determined to be appropriate.

6.0 Surveillance Observations (61726)

6.1 Inspection Scope

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

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

- procedure 0-OSP-0622, Safety Injection System Inservice Test;
- procedure 3-OSP-055.1, CCW to Emergency Containment Cooler Inlet/Outlet Valve Actuator Overhaul/Maintenance;
- procedure 3-OSP-075.2, Auxiliary Feedwater Train 2 Operability Verification;
- procedure 3-OSP-041.4, Unit 3 RCS Leak Rate Calculation;
- procedure 4-OSP-089, Unit 4 Main Turbine Valves Operability Test; and
- procedure OP-12404.1, Unit 4 Flux Mapper (Rod G-5).

The inspectors determined that the above testing activities were performed in a professional manner and met the requirements of the TSs.

6.2 Inspection Findings

6.2.1 Unit 3 RCS Leak Rate

As discussed in NRC Inspection Report No. 50-250,251/93-22, section 5.2.2, the licensee noted an increase in RCS unidentified leakage since February 1993. On September 30, 1993, the leak rate, as determined per 3-OSP-041.4, RCS Leak Rate Calculation, increased to a value of 0.8 gpm. TS 3.4.6.2.b limits this leakage to 1.0 gpm. Based on this leakage, the licensee made a containment entry and initiated a unit shutdown. (Refer to sections 7.2.1 and 9.2.1 for additional information.)

The inspectors reviewed the surveillance procedures (OSP), monitored RCS leak rate indications in the control room, and discussed this issue with the appropriate licensee personnel. The inspectors concluded that the licensee acted appropriately in monitoring the leakage at an increased surveillance frequency and that actions to shut down the unit were conservative.

6.2.2 ECC Testing

During the performance of procedure 3-OSP-055.1, the 3A ECC outlet valve (CV-3-2908) did not fail open upon isolation of instrument air as required. A WR was written, and the pilot valve associated with valve was replaced. This appears to be a repeat event. The inspectors discussed this issue with the maintenance engineer. Testing was done on the pilot valve, and no defects were identified. The inspectors will continue to monitor this issue.

7.0 Maintenance Observations (62703)

7.1 Inspection Scope

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

The following items were considered during this review, as appropriate: LCOs were met while components or systems were removed from service; approvals were obtained prior to initiating work; activities were accomplished using approved procedures and were inspected as applicable; procedures used were adequate to control the activity; troubleshooting activities were controlled and repair records accurately reflected the maintenance performed; functional testing and/or calibrations were performed prior to returning components or systems to service; QC records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were properly implemented; QC hold points were

established and observed where required; fire prevention controls were implemented; outside contractor force activities were controlled in accordance with the approved QA program; and housekeeping was actively pursued.

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

- WR 9302719701, repair/replacement of the 3A ECC outlet valve pilot valve (Refer to section 6.2.2 for additional information.);

- WR 93016632, Unit 3 pressurizer manway repair (Refer to section 7.2.1 for additional information.);

- troubleshooting and repair of the 4A steam generator feedwater pump discharge check valve (Refer to section 7.2.3 for additional information.);

- WR 93026599, 3A MSIV troubleshooting (Refer to section 7.2.4 for additional information.);

- MSIV 3B and 3C troubleshooting activities (Refer to section 7.2.4 for additional information.); and

- WR 9302221201, AFW pump inspection (Refer to section 7.2.5 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 with the exceptions noted in sections 7.2.4 and 7.2.5.

7.2 Inspection Findings

7.2.1 Unit 3 Pressurizer Manway Repair

Based on results from containment inspections, the licensee shut down Unit 3 on September 30, 1993, in order to repair a steam leak on the Unit 3 pressurizer manway. (Refer to sections 6.2.1 and 9.2.1 for additional information.) The licensee initiated a condition report (No. 93-845), a work order (No. 93016632), and an engineering evaluation which included input from the vendor (Westinghouse). The licensee inspected the manway flange area and determined that the flexitallic gasket was damaged for an arc of 180° and that the flange had several areas of erosion/corrosion from steam cuts and from boric acid corrosion. In addition, two of the studs and respective stud holes were damaged. This was documented on PTN quality control report No. 93-0980.

The pressurizer shell is carbon steel with a stainless steel cladding for corrosion resistance. The manway nozzle and flange have a stainless steel insert in which the gasket seats. This flexitallic gasket is an asbestos filled spiral wound metal type. The insert is screwed into the cladding material. The manway cover is then bolted to the manway flange.

The licensee performed the repair per procedure O-GMM-041.1, Pressurizer Manway Removal and Installation. A vendor was contacted and assisted in flange and cladding machining and repair activities per WSI Procedure No. TP33101P-1, Revision 0. Engineering guidance and repair instructions were promulgated in Condition Report No. 93-845.

The licensee completed the machine repair of the flange and insert, replaced the gasket material, repaired and cleaned the studs and holes, replaced the cover, and torqued the bolts. The licensee inspected the repairs and performed NDE. Once at rated pressure, a leak check was also performed. All post maintenance testing activities were satisfactory.

The inspector reviewed the work package including the PWO, the procedures, the condition report and response, the engineering evaluations, and the appropriate related documentation. The inspector also reviewed the licensee's root cause failure analysis and related corrective actions.

The licensee concluded that there were three likely root causes: (1) excessive gasket crush due to a recent change in the vendor recommendations, (2) interference between the insert retaining screws and the manway cover due to the existing small clearances which may have impeded gasket loading, and (3) potential gasket damage during installation of gasket in 1991. The licensee was unable to conclude which root cause was the most probable. However, the licensee implemented corrective actions to ensure that all root causes would be appropriately addressed.

The inspector reviewed the licensee root causes and related corrective actions. Selected corrective actions were verified to be implemented. The inspector concluded that licensee repair and replacement activities for the pressurizer manway leak were appropriate and were effectively coordinated. In addition, the inspector noted strong engineering support for these repair activities.

7.2.2 Leak Sealant Practices at Turkey Point

The inspector assessed the licensee's policy and procedures concerning the use of leak sealants on both safety-related and non-safety-related components. Administrative procedure O-ADM-723, On-Line Temporary Leak Repairs (revised June 3, 1993), and vendor procedures N-93213 and N-92528 associated with two leak

repairs that had been performed earlier were also reviewed. In addition, this issue was discussed with plant staff including engineers, planners, and Furmanite technicians. A list of all leak sealant repairs performed in the past three years was also reviewed. The following observations were noted by the inspector:

- Turkey Point has used Furmanite as a temporary method to repair leaks on both safety-related as well as non-safety-related components. There are two Furmanite technicians permanently located at the site. Approximately 200 leaks have been sealed since 1991 using Furmanite, predominantly on non-safety related components. In accordance with Generic Letter No. 90-05, the licensee does not perform temporary non-code repairs using Furmanite without prior NRC approval.

- The procedure for a maintenance job involving leak repair using Furmanite, including supporting calculations and limits on the amount of sealant to be injected, was developed by Furmanite. This procedure was reviewed and approved by Turkey Point Engineering in the event the components involved are safety-related. Engineering then provided an evaluation associated with the job as well as specifies the type and maximum amount of compound used.

- Additionally, the PNSC as well as QC reviewed work packages associated with safety-related jobs. A PWO for a permanent repair or replacement of the component was simultaneously written with the PWO associated with the Furmanite job. Based on the list of Furmanite jobs that have been performed since 1991, the inspector noted that a permanent repair was not always performed during the next available opportunity such as a refueling outage. All safety-related repairs were performed.

The inspectors concluded that the procedure as well as controls imposed on the process were adequate.

7.2.3 Unit 4 4A Steam Generator Feedwater Pump Discharge Check Valve Repair

Inspection of the 4A steam generator feedwater pump discharge check valve (valve 4-20-118) on October 13, 1993, per an action item in Condition Report No. 93-777 confirmed that one of two disc pins and its retaining screw were missing. These pieces had previously been found inside the 6A feedwater heater during investigations of reported noises. (Refer to section 8.2.1 of NRC Inspection Report No. 50-250,251/93-22 for additional information.) The licensee also found a 1/16-inch deep gouge on both the valve bonnet and seal ring which was caused by an embedded piece of wire.

The licensee attributed the root cause of the disc pin of valve 4-20-118 vibrating loose to be improper retaining screw tack welds. Normally, two tack welds are provided (one at each side) to stop the rotation of the retaining screw. However, the welds on this failed valve provided an inadequate stop in that they were too short and sloped away from the retaining pin. Although there were design requirements for the number of tack welds (2) and the maximum gap between the weld and the head of the retaining screw (1/16 inch), no drawing or procedure defined the minimum size of the welds themselves. As a result, a vendor (Crane-Aloyco) representative recommended a minimum height of 1/8 inch and a length of approximately 1/2 inch. In addition, it was also identified that the installed disc did not incorporate machined flats at the retaining screw locations in order to facilitate installation of the tack welds. The use of machined flats is the current Crane-Aloyco practice as demonstrated by the replacement disc assemblies stocked at Turkey Point.

Inspection results of the remaining unaffected and disc sleeve verified no damage or distortion due to the extended operating period coupled with flutter of the disc during pump operation. Inspection of the 4B steam generator discharge check valve (valve 4-20-218) on October 13, 1993, also verified that no failure had occurred and that the retaining screw tack welds in this valve were adequate to stop rotation of the retaining screws.

The licensee documented this information in Condition Report No. 93-891, and prior to returning valve 4-20-118 to service, the licensee completed the following corrective actions:

- The seating surface of the valve bonnet was machined in accordance with specific criteria, and the vendor inspected the completed bonnet prior to installation.

- The inspection results of the east side disc pin and disc sleeve were documented in Condition Report No. 93-891.

- OTSC No. 93-619 was generated to incorporate the revised tack weld requirements and to extend cleanliness controls through assembly of the bonnet/pressure seal.

In addition to these actions, the licensee plans to issue a drawing change request (DCR-TPM-93-479) by October 28, 1993, in order to incorporate the detailed tack weld requirements into drawing No. 5610-M-60D-7, Sheet 1.

The inspector witnessed portions of the licensee's maintenance activities and reviewed Condition Report No. 93-891. The inspectors also verified that the changes made by OTSC No. 93-619 met the intent of the corrective actions specified in the condition report. The licensee's efforts with regard to this check valve repair were both efficient and effective.

7.2.4 Unit 3 MSIV Troubleshooting

On October 18, 1993, during troubleshooting of a potential DC ground on a solenoid valve associated with the 3B MSIV, leads associated with the C MSIV were inadvertently lifted. At the time of the event, Unit 3 was in Mode 2 with the B MSIV closed for troubleshooting associated with the ground. The A and C MSIVs were open. Inadvertent lifting of the leads associated with the C MSIVs made the C MSIV inoperable from the alternate shutdown panel.

Troubleshooting for the ground including meggering was being conducted in accordance with procedure O-GMI-102.1, Troubleshooting and Repair Guidelines. An inspection plan with specifics was also developed by component engineering as a reference for the I&C technicians.

The job involved initially identifying the terminal points for the leads to be lifted and noting them on the lifted lead data sheet. This data sheet was then to be used to document the appropriate lifting and landing of the leads. The task associated with the identification, lifting, and landing of the leads was required to be independently verified in accordance with procedure O-ADM-031, Independent Verification, and procedure O-GMI-102.1.

During the identification of the terminal points for lifting the leads, a cable tag was misread, and two terminal points associated with the misread cable were documented in the lifting and landing data sheet. The leads identified to be lifted were for the 3C MSIV as opposed to the 3B MSIV. This identification was performed by an I&C technician and independently verified by his job supervisor.

The leads identified on the data sheet were then correctly lifted and independently verified. The lifted leads were for the C MSIV versus for the B MSIV.

The leads were relanded following completion of troubleshooting. The C MSIV was degraded from approximately 11:00 p.m. until 11:30 p.m. on October 18, 1993. The fact that wrong leads had been lifted was realized later during a conversation of the activities performed between I&C and engineering at 1:45 a.m. on October 19, 1993.

The control room was notified of the occurrence. With the B MSIV de-energized closed and the C MSIV in degraded mode, TS 3.0.3 was initially entered. After further review, the licensee retracted this entry as the B MSIV was closed, which is the safe position for the valve. The inspector concluded that the licensee appropriately determined that TS 3.0.3 was not applicable. The C MSIV was tested satisfactorily, and returned to service at 2:25 a.m. on October 19, 1993.

The inspectors discussed this event with the I&C supervisor. Both individuals involved in the job were counselled by the I&C supervisor. Additionally, the licensee plans to discuss this event with all field supervisors as well as I&C technicians. Because the criteria in Section VII.B of the NRC Enforcement Policy were met, this failure to identify and lift the correct leads and to implement the independent verification procedure is identified as a licensee-identified NCV. This item will be tracked as NCV 50-250,251/93-24-01, Wrong Leads Lifted/Independent Verification Failure.

7.2.5 AFW Pump Inspection

The licensee installed a portable oil cleaning rig on the AFW oil tanks without declaring the AFW pump(s) inoperable. A temporary hose was dipped into the oil tank, routed through the filter, and returned back to the tank. The inspector noted that though appropriate precautions were taken, the AFW pump(s) should have been declared technically inoperable during the time that the rig was aligned to the tank. This issue was discussed with plant management, and the Plant General Manager was in concurrence. The inspectors concluded that the pump would have functioned in this condition. This issue was identified by the inspector during the system walkdown discussed in section 8.0. The inspector considered not calling the pump inoperable during the time that the oil rig was installed a weakness.

8.0 Engineered Safety Features Walkdown (71710)

8.1 Inspection Scope

The inspectors performed an inspection designed to verify the status of the HHSI and AFW systems. This was accomplished by performing a complete walkdown of all accessible equipment. The following criteria were used, as appropriate, during this inspection:

- systems lineup procedures matched plant drawings and as-built configuration;

- housekeeping was adequate, and appropriate levels of cleanliness were being maintained;

- valves in the system were correctly installed and did not exhibit signs of gross packing leakage, bent stems, missing handwheels, or improper labeling;

- hangers and supports were made up properly and aligned correctly;

- valves in the flow paths were in correct position as required by the applicable procedures with power available, and valves were locked/lock wired as required;

- local and remote position indication was compared, and remote instrumentation was functional; and

- major system components were properly labeled.

8.2 Inspection Findings

8.2.1 HHSI and AFW System Walkdowns

The inspectors walked down the Unit 3 and 4 HHSI systems and the common AFW system. Minor deficiencies were discussed with the appropriate engineering, maintenance, and operations personnel. The inspectors concluded that the HHSI and AFW systems were appropriately aligned for the standby/automatic condition.

Several questions concerning accuracy of P&IDs, adequacy of installed hangers, and vulnerability of a common mode failure of the AFW system following a main steam line rupture were raised by the inspectors. Engineering response to these questions was thorough and aggressive.

9.0 Operational Safety Verification (71707)

9.1 Inspection Scope

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

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

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

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

9.2 Inspection Findings

9.2.1 Unit 3 Containment Entries

The inspectors made two Unit 3 containment entries during the inspection period. The first occurred on September 30, 1993, with the unit at full power. The second entry occurred on October 6, 1993, with the unit shut down in Mode 3 (Hot Standby) at rated temperature and pressure.

The entry at power was made to inspect the containment due to the high RCS leak rate. (Refer to section 6.2.1 for additional information.) The licensee assembled several inspection teams with personnel from HP, operations, engineering, security, and safety. Plant management personnel were also involved. The entries were performed in accordance with procedure O-ADM-009, Containment Entries When Containment Integrity Is Established.

The inspector attended the pre-entry briefing and reviewed the associated RWP. The inspector verified that entry precautions and requirements were met. These included RWP review, heat stress precautions, confined space entry requirements, security and safety coverage, neutron and gamma dose monitoring, radioactivity airborne monitoring, and containment integrity precautions.

During the entry, a leak from the pressurizer steam space manway was identified. Licensee actions are detailed in section 7.2.1 of this report.

The inspector concluded that management responded conservatively and appropriately to the identified leak. Further, the entry was professionally conducted and management oversight was effective in assuring a safe at-power containment entry.

The second entry was made by the inspector to independently verify containment conditions prior to restart from the Unit 3 outage. (Refer to section 9.2.3 for additional information.) The inspector performed the entry per procedure O-ADM-009. Items checked included RCS leakage, housekeeping, material conditions, cleanliness, equipment status, and radiological conditions. The inspector concluded that the containment condition and related safety equipment was appropriate to support Unit 3 restart.

9.2.2 Operations Shift Turnover/Relief

The inspectors reviewed the control room shift turnover procedures and practices. Administrative procedures O-ADM-200, Conduct of Operations, and O-ADM-202, Shift Relief and Turnover, delineate the licensee's requirements for these activities. The inspectors reviewed the procedures and verified implementation during numerous shift turnover periods on various shifts and operating crews. The inspectors noted that the turnover activity included a shift briefing by the NPS, ANPS, and NWE. The inspectors found these briefings to be very informative, and supervision discussed equipment problems, special conditions, and shift priorities. Further, maintenance personnel also attended these meetings to discuss work priorities.

However, the inspectors made the following observations while attending these meetings: individuals would at times sit on panels and desks; hard hats were either worn in the control areas or were rested on control panels; eating, drinking, and tobacco chewing occurred; and drinks were rested on control room panels.

Although these activities did not degrade the effectiveness and thoroughness of turnover briefing information, the inspectors stated that these issues could have a negative impact. The inspectors discussed these issues with operations and plant management personnel. Operations night orders were issued addressing these items and discussions were held at turnover meetings. The inspectors noted the licensee to be very responsive to these concerns, and no further problems were noted during the rest of the inspection period.

9.2.3 Unit 3 Outage and Restart

On September 30, 1993, Unit 3 began a SNO to repair the pressurizer manway leak. (Refer to sections 3.1, 6.2.1, and 7.2.1 for additional information.) Additional work items and surveillance testing activities were scheduled and performed during the outage.

The inspectors reviewed the licensee's SNO schedule, attended periodic turnover and status meetings, discussed the outage progress and issues with the shift managers and other personnel, and observed work and test activities. The inspectors concluded that the licensee demonstrated conservatism in beginning an outage prior to exceeding the TS RCS unidentified leakage limit. Further, the inspectors concluded that the outage was well planned and controlled and that the shift outage managers were effective in providing oversight and control of all outage-related activities.

The inspectors monitored portions of the October 5, 1993, Unit 3 restart. Activities and evaluations were performed effectively and in accordance with procedures.

9.2.4 Control Room Information Tags

The inspector reviewed the licensee's program and procedures for displaying control room panel information such as operator aids and temporary information tags. Administrative procedure AP-0103.36, Control of Operator Aids and Temporary Information Tags, delineates the requirements for posting, controlling, and removing such information.

The inspector walked down the control boards checking for operator aids and information tags, reviewed the index for these tags, and discussed this issue with licensed operators and management personnel. The inspector noted that a number of temporary information tags had been in existence since 1988. The licensee's procedure states that the need for a permanent tag should be considered after six months. The licensee stated that it would review this issue. Further, the inspector noted that some control room board deficiencies were identified with both an information tag and a green sticker (indicating that a PWO was open). This appeared to be duplication, and the licensee agreed.

The inspector concluded that the licensee's program generally met the intent of procedure AP-0103.36 and that the licensed operators were knowledgeable regarding displayed control board information. However, minor weaknesses were identified in the program. The licensee was responsive to these weaknesses, and at the close of the period, the licensee was correcting long-standing items.

9.2.5 FTS-2000 Out of Service

On October 7, 1993, it was discovered that the FTS-2000 ENS phones were inoperable. After an investigation by the licensee, it was determined that the problem was outside the scope of the direct control of the licensee. The NRC was notified and following troubleshooting and maintenance performed by AT&T, the FTS-2000 phones were returned to service on October 12, 1993. The problem was attributed to a short in a switching power supply located at the nearby fossil plant.

This is the second time in the past two months that the FTS-2000 phones have become inoperable. The inspectors will continue to monitor issues associated with the FTS-2000 phone system to determine if any additional action on both licensee's or NRC's part is warranted to increase the reliability of the FTS-2000 system.

9.2.6 Inadvertent Dilution Event on Unit 3

On October 22, 1993 (Friday night) at approximately 9:10 p.m., the licensee discovered that an inadvertent dilution had occurred on Unit 3. Reactor power, as seen on the analog average of the four power range NIs, had increased to approximately 102.89%, and Tavg had increased from 574.0°F to 576.5°F. Upon discovery, a boration was immediately initiated, and control rods were inserted to restore power to below 100% and to lower Tavg to within the normal operating band. Unit 3 was above 102% indicated NI power for approximately 10 minutes. The problem was recognized when the annunciator for the overpower rod stop was received as a result of indicated NI greater than the setpoint of approximately 102.7%.

This event began after a satisfactory completion of a 4-hour RCS leak rate, the Unit 3 RCO diluted the RCS to raise Tavg to bring it closer to Tref. The intention was to add 100 gallons of primary water (boron free) to the RCS to compensate for core burnup. The unit was in the middle of core life with the boron concentration of approximately 424 ppm.

The dilution process involves taking suction from the primary water storage tank via the primary water transfer pump through the batch totalizer to the VCT. The amount of primary water to be added to the RCS is set on the totalizer. The charging pump, which takes suction from the VCT, then pumps the primary water into the RCS through its normal injection path. When the volume of injected primary water equals that set on the totalizer, the primary water addition is terminated by the automatic closure of two flow control valves. Injection of primary water via the VCT ensures a gradual dilution as it mixes with water from normal letdown.

The procedural steps to perform this evolution are outlined in section 5.3 of procedure 0-OP-046, CVCS-Boron Concentration Control. Since this is a routine and frequent evolution, operators do not normally have the procedure open while performing the dilution steps. This is normal and is considered to be within their expected knowledge/performance level. Additionally, the procedure does not require any signoffs.

The operator, instead of entering 100 gallons in the digital totalizer, entered 1,000 gallons and initiated the dilution. The operator then got distracted from the ongoing dilution due to involvement in a liquid release that had been initiated earlier. Normally, the 100 gallon addition takes approximately 2 to 3 minutes. With the totalizer set at 1,000 gallons, this dilution lasted for approximately 20 minutes. Step 5.3.2.9 of procedure 0-OP-046 requires the operator to observe changes in Tavg and stop dilution if Tavg increases greater than 1.5°F above Tref. However, this was not done, and Tavg went as high as 2.6°F above Tref.

Additionally, indicated NI power increased to above 102%. With Tavg greater than Tref, inward control rod motion initiated to bring Tavg closer to Tref. Also, with indicated NI power at approximately 102.7%, annunciator B-6/3, Over Power Rod Stop, was received. Presumably, this alerted the operator of the ongoing dilution. A boration was initiated and control rods were inserted to restore power to below 100% and Tavg to within the normal operating band. The Acting Operations Manager was notified of this event. A decision was made to take the involved RCO off shift, and he was later disciplined.

The Plant General Manager became aware of the event later on that night when he called the control room to get the plant status. The resident inspectors and the Site Vice President became aware of the event the following Monday (October 25, 1993).

Upon becoming aware of the event, the resident inspectors reviewed reportability and concluded that no notifications were required. The TSs and FSAR were also reviewed with respect to the dilution event. The inspectors determined that although reactor power of 100% was briefly exceeded, the event was bound by the accident analysis for inadvertent dilution described in the FSAR and that sufficient margin existed for DNB and fuel cladding protection. It should also be noted that without any operator action, the event would have been terminated either by automatic inward rod motion or by the OPΔT, OTΔT, or the NI high flux automatic reactor trips. A calorimetric and a reactivity balance were later performed by reactor engineering. They determined that as a result of the reduction in density and boron concentration in the RCS, the indicated NIs were reading conservatively high during the dilution event. Based on the calculation, actual reactor power did not exceed approximately 101.4%. The inspectors reviewed the licensee's determination, and concluded it to be appropriate.

Notwithstanding the above, the inspectors are concerned about this overdilution event because it brought to light a problem in the area of conduct of operations. This included failure to monitor key parameters during a reactivity change as required by procedure 0-OP-046, failure to log reactivity changes in the RCO log book in accordance with procedure 0-ADM-204, Operations Narrative Log Books, and the potential impact of just having one operator in the control room. Additionally, the inspectors believe that not having an audible counter when the totalizer is in service also contributed to the operator not noticing the overdilution event. This failure to follow the requirements of procedures 0-OP-046 and 0-ADM-204 will be classified as VIO 50-250,251/93-24-02, Inadvertent Overdilution.

The inspectors discussed this event at length with senior plant management including the Site Vice President and Plant General Manager. They are in concurrence with the inspectors' concerns.

The inspectors will continue to monitor licensee performance in this area.

9.2.7 Emergency Plan Drill

The inspector observed portions of an announced emergency plan drill on October 27, 1993. The inspector concluded that drill performance was satisfactory. Further, the licensee was effective during drill conduct and critique activities.

9.2.8 General Results

As a result of routine plant tours and various operational observations, the inspectors determined that the general plant and system material conditions were satisfactorily maintained, the plant security program was effective, and the overall performance of plant operations was generally satisfactory.

10.0 Plant Events (93702)

10.1 Inspection Scope

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

10.2 Inspection Findings

10.2.1 Personnel Contamination Events

During the Unit 3 SNO (Refer to section 9.2.3 for additional information.), two events occurred which resulted in personnel skin and clothing contamination. These both occurred on October 5, 1993. The first event occurred in the pipe and valve room during RHR system valve local leak rate testing equipment restoration. I&C personnel were disconnecting a test rig. During the removal process, residual pressure in the lines sprayed onto one technician causing skin and clothing contamination and also causing floor and shoe contamination on four other individuals. The second event occurred inside containment in the cavity area where personnel were disconnecting a spool piece associated with the pressurizer manway repair work. Residual pressure and water in the line resulted in the area being sprayed. No skin

contaminations occurred; however, the two individuals received clothing contaminations probably during protective clothing removal.

The licensee reviewed each event by initiating condition reports, radiological investigation reports, and contamination reports. The individual with facial skin contamination (10,000 dpm) was successfully deconned, and a whole body count did not identify any internal contamination. The remaining individuals' clothing were either deconned or disposed of as radioactive waste. The licensee also performed skin dose assessments for the affected individuals. Due to low levels of contamination and the short time for exposure, no dose was required to be assigned.

Further, the licensee conducted a post-event critique meeting on October 6, 1993. HP, operations, engineering, maintenance, and management personnel attended. Causal factors included poor communication among the workers, weak procedural controls, and a lack of attention to detail. Corrective actions included procedure and equipment enhancements, discussion of the events at various site meetings, modifications to training programs, review of the event at the ALARA review committee, and changes to protective clothing requirements during future similar jobs. Further, the personnel involved were deconned, and the affected contaminated areas outside containment were cleaned and released.

The inspector followed up on these events by reviewing the associated reports, by attending the event critique meeting, and by discussing the events with HP management personnel. The inspector reviewed the root cause determinations and verified selected corrective actions. The inspector concluded that the licensee aggressively and thoroughly followed up these two contamination events partly caused by a lack of attention to detail by workers and HP personnel. Root cause and corrective action determination appeared to be appropriate.

10.2.2 Unit 3 Feedwater Isolation Signal While in Mode 4

At 11:51 p.m. on October 5, 1993, with Unit 3 in Mode 4, a feedwater isolation signal was generated on high level in the B steam generator. The licensee attributed this rise in steam generator level to a leaking feedwater bypass valve (FCV-3-489) after the A standby steam generator feedwater pump was started. Operators had started the A standby steam generator feedwater pump at approximately 11:35 p.m. and subsequently noted a rise in the level of the 3B steam generator with the applicable feedwater regulating bypass valve (FCV-3-489) demanded and indicated closed. Operators attempted to manually isolate the feedwater bypass valve, but the level in the 3B steam generator continued to rise due to valve leakby. At 11:51 p.m., when the level in the 3B steam generator reached 80%, a feedwater isolation signal was generated, and blowdown was placed in service at approximately

midnight. The 3B steam generator level peaked at 90% and was then brought into the normal operating band.

The licensee notified the NRC Operations Center of a Significant Event in accordance with 10 CFR 50.72(b)(2)(ii), ESF Actuation, at 1:53 a.m. on October 6, 1993. At 12:30 p.m. on October 8, 1993, the licensee retracted this event notification on the basis that the main feedwater system is not required while the unit is in Mode 4 (Hot Shutdown), that the system was isolated at the time of the ESF actuation signal, and that no valve actuation occurred as a result of the ESF signal.

As a result of this event, the licensee generated Condition Report No. 93-860 and an Operational In-House Event Preliminary Investigation Report. The licensee initiated a root cause review and implemented corrective actions.

The inspectors reviewed the licensee's Operational In-House Event Preliminary Investigation Report and Condition Report No. 93-860 and determined the licensee's corrective actions to be adequate. However, the inspectors noted a weakness in that it was not recognized by the involved operators that the steam generator level increase could easily have been terminated by securing the standby steam generator feedwater pump which was feeding the steam generators.

10.2.3 Unit 3 Reactor Trip While Subcritical

During the September 30, 1993, controlled plant shutdown to effect repairs on the leaking Unit 3 pressurizer manway discussed in section 7.2.1 of this report, an automatic reactor trip occurred at approximately 10:05 p.m. Just prior to the trip, control rods were being inserted manually into the core. When the reactor power decreased to below 1×10^{-10} amps on the IR detectors, both the SR high voltage power supplies energized as required. SR channel N32 responded normally. However, SR channel N31 was observed to peg high at greater than 1×10^{6} counts per second. With N31 greater than the reactor trip setpoint of 1×10^{6} counts per second, the one out of two coincidence logic for RPS actuation was met, and an automatic reactor trip occurred.

Post-trip response was normal with a few exceptions. Notably, the count rate for N31 remained about 200 cps above the N32 count rate following the trip. Additionally, the green indication light on MSIV POV-3-2604 did not come on upon MSIV closure. WRs were written to investigate and repair the cause of the SR instrument failing high upon energization and the MSIV indication problem.

I&C performed troubleshooting on the SR detection system and determined that the high voltage power supply to N31 had failed. Nominally the high voltage power supply, located in the source

range drawer in the control room, provided 1800 volts DC excitation to the SR detector. During troubleshooting, I&C personnel observed the output voltage of the power supply spike to approximately 2300 volts DC. The output voltage was also noted to be unstable when the voltage adjustment potentiometer was manipulated. The cause for N31 count rate to be 200 cps above N32 following the trip was found to be due to the setting of the gamma discriminator bias. It was concluded that the gamma discriminator bias did not contribute to the reactor trip.

The power supply to N31 was replaced. Additionally, detector cables associated with N31 were meggered with satisfactory results.

The inspectors observed portions of the troubleshooting associated with the failed power supply as well as attended various meetings associated with the trip as well as the investigation concerning the failed SR detector power supply. The inspectors concluded that licensee actions were conservative and appropriate.

Following the performance of troubleshooting activities and repairs on the pressurizer manway, the licensee returned the unit to service on October 7, 1993, and 100% reactor power was re-achieved on October 8, 1993. The inspectors observed portions of this startup and concluded that the startup activities were conducted in a professional manner.

11.0 Management Meetings (30702)

11.1 Inspection Scope

The inspectors attended the meetings discussed below.

11.2 Inspection Findings

11.2.1 Enforcement Conference

The inspector attended an Enforcement Conference on October 5, 1993, in the Regional Office. At the conference, issues associated with two 1987 DOL discrimination cases were discussed. The results of the meeting and any NRC disposition of the issues will be forwarded by separate correspondence.

11.2.2 Engineering Meeting

A meeting with representatives from the FPL engineering staff and the NRC resident and regional offices was conducted at the FPL Corporate Office in Juno Beach, Florida, on October 20, 1993. The topics of discussion included organization and staffing changes; engineering initiatives in the areas of nuclear safety, availability, cost, and employee development; engineering self assessment; and 1994 complex modifications for both the St. Lucie

and Turkey Point facilities. This meeting was beneficial in keeping the NRC informed of licensee initiatives and aware of the status of ongoing enhancements.

12.0 Exit Interview

The inspection scope and findings were summarized during management interviews held throughout the reporting period with the Plant General Manager and selected members of his staff. An exit meeting was conducted on October 29, 1993. The areas requiring management attention were reviewed. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee. The inspectors had the following findings:

Item Number	Description and Reference
50-250,251/93-24-01	NCV - Wrong Leads Lifted/Inadequate Verification (section 7.2.4).
50-250,251/93-24-02	VIO - Inadvertent Overdilution (section 9.2.6).

13.0 Acronyms and Abbreviations

ADM	Administrative
AFW	Auxiliary Feedwater
ALARA	As Low as Reasonably Achievable
ANPS	Assistant Nuclear Plant Supervisor
AP	Administrative Procedure
AT&T	American Telephone and Telegraph
CCW	Component Cooling Water
CFR	Code of Federal Regulations
cps	Counts Per Second
CV	Control Valve
CVCS	Chemical and Volume Control System
DC	Direct Current
DCR	Drawing Change Request
DNB	Departure From Nucleate Boiling
DOL	Department of Labor
dpm	Disintegrations Per Minute
DPR	Docket Power Reactor (Plant License)
ECC	Emergency Containment Cooler
ENS	Emergency Notification System
ESF	Engineered Safety Feature
F	Fahrenheit
FCV	Flow Control Valve
FL	Florida
FPL	Florida Power & Light
FSAR	Final Safety Analysis Report
FTS	Federal Telecommunications System
GMI	General Maintenance - I&C
GMM	General Maintenance - Mechanical

gpm	Gallons Per Minute
HHSI	High Head Safety Injection
HP	Health Physics
HPS	Health Physics - Surveillance
I&C	Instrumentation and Control
IR	Intermediate Range
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MOV	Motor Operated Valves
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NI	Nuclear Instrument
NPS	Nuclear Plant Supervisor
NRC	Nuclear Regulatory Commission
NWE	Nuclear Watch Engineer
OM	Operating Manual
OP	Operating Procedure
OPΔT	Over Power Delta Temperature
OSP	Operations Surveillance Procedure
OTSC	On-the-Spot Change
OTΔT	Over Temperature Delta Temperature
PMM	Preventative Maintenance - Mechanical
PNSC	Plant Nuclear Safety Committee
POV	Power Operated Valve
ppm	Parts Per Million
PTN	Project Turkey Nuclear
PWO	Plant Work Order
QA	Quality Assurance
QC	Quality Control
RCO	Reactor Control Operator
RCS	Reactor Coolant System
RHR	Residual Heat Removal System
RPS	Reactor Protective System
RWP	Radiation Work Permit
SNO	Short Notice Outage
SR	Source Range
Tavg	Average Temperature
TPCW	Turbine Plant Cooling Water
TPM	Turkey Point Modification
Tref	Reference Temperature
TS	Technical Specification
URI	Unresolved Item
VCT	Volume Control Tank
VIO	Violation
WR	Work Request
WS	Waste System
WSI	Welding Services, Inc.