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

Report Nos.: 50-250/93-21 and 50-251/93-21

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

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

Facility Name: Turkey Point Units 3 and 4

Inspection Conducted: July 24 through August 20, 1993

Inspectors: _____ 9/16/93
R. C. Butcher, Senior Resident Inspector — Date Signed

_____ 9/16/93
B. B. Desai, Resident Inspector — Date Signed

_____ 9/16/93
L. Trocine, Resident Inspector — Date Signed

Accompanying Inspectors: T. P. Johnson, Senior Resident Inspector, Salem and Hope Creek
George Schnebli, Resident Inspector, Browns Ferry

Approved by: _____ 9/17/93
K. D. Landis, Chief — Date Signed
Reactor Projects Section 2B
Division of Reactor Projects

## SUMMARY

Scope:

This routine resident inspector inspection involved direct inspection at the site in the areas of surveillance observations, maintenance observations, operational safety, and plant events. Backshift inspections were performed on July 24-25 and 27-28 and August 1 and 16-19, 1993.

Results:

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

Violation 50-250,251/93-21-01, Failure to Follow a Procedure Resulting in a Feedwater Transient and Subsequent Reactor Trip (paragraph 8.f).

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

- Plant Operations

  The approach to criticality following the Unit 4 outage was performed in a professional manner with good communications (paragraph 8.c). A concern was noted regarding the performance of procedural steps out of sequence, the lack of command and control that resulted in a feedwater transient and subsequent reactor trip, and the lack of good communications needed to ensure that both control room and field personnel were aware of the performances of significant evolutions (paragraph 8.f).

- Engineering

  A weakness was noted in the lack of attention to detail on the Unit 4 design package for the elimination of the turbine runback on a dropped rod (paragraph 8.e). A strength was also noted for Engineering's quality perspective in the identification of the inadvertent removal of a wire on the Unit 4 turbine runback circuitry during preparation for the performance of the same modification on Unit 3 (paragraph 8.e).

The following general comment was also noted:

Management's decision to remove Unit 4 from service in order to facilitate the replacement of a pressurizer spray mini-flow bypass valve due to a minor unisolable leak was conservative (paragraph 8.c). This was noted as a strength.

The inspectors reviewed the following outstanding item:

(Closed) License Event Report 50-251/93-002, Reactor Trip Due to Manual Turbine Trip (paragraph 4).

## REPORT DETAILS

1. Persons Contacted

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. Gianfrencesco, Support Services Supervisor
J. H. Goldberg, President, Nuclear Division
E. F. Hayes, 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, Acting Director, Nuclear Licensing
* 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.

NRC Resident Inspectors

R. C. Butcher, Senior Resident Inspector
* B. B. Desai, Resident Inspector
* L. Trocine, Resident Inspector

Other NRC Personnel on Site

T. P. Johnson, Senior Resident Inspector, Salem and Hope Creek
G. A. Schnebli, Resident Inspector, Browns Ferry

* Attended exit interview on August 20, 1993

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

2. Other NRC Inspections Performed During This Period

None

3. Plant Status

Unit 3

At the beginning of this reporting period, Unit 3 was operating at approximately 15% power in order to facilitate the repair of a steam leak on the 3B MSR drain line, cleaning of the 3A north and 3A south waterboxes, and cleaning of the 3A and 3B TPCW heat exchangers. (Refer to paragraphs 3 and 8.i of NRC Inspection Report No. 50-250,251/93-19.) The unit had been on line since January 20, 1993. The following evolutions occurred on this unit during this assessment period:

- At 3:15 a.m. on July 24, 1993, power ascension was commenced following the repair of a steam leak on the 3B MSR drain line. In order to facilitate cleaning of the 3A TPCW heat exchanger, reactor power was stabilized at 50% at approximately 6:40 a.m. At 6:00 p.m., the licensee commenced a slow power increase and removed the 3B TPCW heat exchanger from service for cleaning. This heat exchanger was returned to service at 9:30 a.m. on July 25, 1993. Power ascension from 75% was re-commenced at a rate of 10% per hour, and 100% reactor power was achieved at 12:15 p.m. (Refer to paragraph 8.a for additional information.)

- At 12:15 p.m. on July 25, 1993, Unit 3 broke the previous Turkey Point record for continuous days on line. This record (185 days, 15 hours, and 43 minutes) was set on March 20, 1988.

Unit 4

At the beginning of this reporting period, Unit 4 was operating at 100% power and had been on line since June 27, 1993. The following evolutions occurred on this unit during this assessment period:

- At 5:55 p.m. on August 12, 1993, a load reduction was commenced in order to facilitate the replacement of the pressurizer spray mini-flow bypass valve (4-524A) around pressurizer spray valve PCV-4-455B. (Refer to paragraph 8.c for additional information.) Unit 4 was taken off line and entered Mode 2 at 8:34 p.m., and Mode 3 was entered at 8:44 p.m. On August 13, 1993, Unit 4 entered Modes 4 and 5 at 5:10 a.m. and 10:55 a.m., respectively.

- Following RCS filling and venting, RCS heatup was commenced at 1:45 a.m. on August 15, 1993. A pressurizer bubble was established at 11:40 a.m., Mode 4 was entered at 1:36 p.m., and Mode 3 was entered at 10:30 p.m. Normal operating pressure (2235

psig) and temperature (547°F) were established at 3:40 a.m. on August 16, 1993. Reactor startup was commenced at 4:22 p.m., Mode 2 was entered at 5:03 p.m., and criticality was achieved at 5:20 p.m. Mode 1 was entered at 7:55 p.m., Unit 4 was placed back on line at 9:27 p.m., and reactor power was increased to approximately 28% for a chemistry hold. (Refer to paragraph 8.c for additional information.)

- At 10:33 p.m. on August 16, 1993, Unit 4 experienced a turbine trip and subsequent reactor trip from approximately 28% power due to high narrow range level in the 4C steam generator. (Refer to paragraph 8.f for additional information.)

- Reactor startup was commenced at 9:17 a.m. on August 17, 1993. Mode 2 was entered at 9:50 a.m., criticality was achieved at 10:04 a.m., Mode 1 was entered at 1:01 p.m., and Unit 4 was placed back on line at 1:28 p.m. Reactor power was stabilized at 100% at 6:00 a.m. on August 18, 1993. (Refer to paragraph 8.f for additional information.)

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

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

(Closed) LER 50-251/93-002, Reactor Trip Due to Manual Turbine Trip.

This event was discussed in detail in paragraphs 3 and 10.d of NRC Inspection Report No. 50-250,251/93-17 and in paragraphs 3 and 8.a of NRC Inspection Report No. 50-250,251/93-19. On June 22, 1993, the licensee performed a turbine trip test on Unit 4 while it was operating at 100% reactor power, and operators were unable to relatch the turbine trips after the successful completion of this test. As a result, a load reduction was commenced with the intention of taking the turbine off line to troubleshoot and repair the turbine trip latching mechanism. During this load reduction, a loss of turbine control oil pressure occurred with reactor power at approximately 33%. This in turn resulted in a turbine anti-motoring trip followed by a generator lockout. Based on the turbine anti-motoring indication and the generator lockout, operators manually tripped the turbine, and a subsequent reactor trip occurred because reactor power was greater than 10%. The

licensee's subsequent investigations concluded that the cause was an inadvertent operation of the auxiliary governor trip lever by personnel restoring the turbine controls to normal after the turbine trip test. As a result, the licensee installed a guard to prevent the inadvertent operation of the auxiliary governor trip lever. The unrelated inability to relatch the turbine trips was caused by incorrect clearances in the overspeed trip block between the trip relay and the relay bushing and between the relay cup valve and the relay cover plate. These clearances were corrected, and Unit 4 was returned to service on June 26, 1993. This LER is closed.

5. Surveillance Observations (61726)

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

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

- procedure 3-SMI-064.1, Accumulator Level and Pressure Loop Analog Tests; and

- procedure 3-OSP-022.4, EDG Fuel Oil Transfer Pump and Valve Inservice Test.

The inspectors determined that the above testing activities were performed in a satisfactory manner and met the requirements of the TSs. The flow gage associated with the EDG fuel oil transfer pump test was observed to be functioning erratically during the first run of the test. A PWO was written to troubleshoot and repair the gage. The test was rerun satisfactorily. Violations or deviations were not identified.

6. Maintenance Observations (62703)

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

The following items were considered during this review, as appropriate: LCOs were met while components or systems were removed from service; approvals were obtained prior to initiating work; activities were accomplished using approved procedures and were inspected as applicable;

procedures used were adequate to control the activity; troubleshooting activities were controlled and repair records accurately reflected the maintenance performed; functional testing and/or calibrations were performed prior to returning components or systems to service; QC records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were properly implemented; QC hold points were established and observed where required; fire prevention controls were implemented; outside contractor force activities were controlled in accordance with the approved QA program; and housekeeping was actively pursued.

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

- cleaning of Unit 4 TPCW heat exchangers and
- troubleshooting and weld repair of an unisolable leak on pressurizer spray mini-flow bypass valve 4-524A, the bypass valve for pressurizer spray valve PCV-4-455B (Refer to paragraph 8.c 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. Violations or deviations were not identified.

7. Operational Safety Verification (71707)

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

By observation and direct interviews, verification was made that the physical security plan was being implemented. The implementation of radiological controls and plant housekeeping/cleanliness conditions were also observed. In addition, the inspectors reviewed portions of the licensee's GET training program.

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

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

- A and B emergency diesel generators,

- control room vertical panels and safeguards racks,
- intake cooling water structure;
- 4160-volt buses and 480-volt load and motor control centers,
- Unit 3 and 4 feedwater platforms,
- Unit 3 and 4 condensate storage tank area,
- auxiliary feedwater area,
- Unit 3 and 4 main steam platforms, and
- auxiliary building.

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

| Audit Number | Number of Findings | Type of Audit |
|---|---|---|
| QAO-PTN-93-013 | 0 | Control of Computer Software Per Procedure QP 2.15 |
| QAO-PTN-93-014 | 0 | Radioactive effluents (Process Control Program) |
| QAO-PTN-93-015 | 0 | TSs 6.1, 6.2, and 6.5.1 and TQR 1.0 |
| QAO-PTN-93-016 | 1 | June Performance Monitoring Audit |
| QAO-PTN-93-018 | 0 | Radwaste Audit |

No additional NRC followup actions will be taken on the finding referenced above because it was identified by the licensee's QA program audits and corrective actions have either been completed or are currently underway. Plant management has also been made aware of this issue.

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

8. Plant Events (93702)

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

a. At 3:15 a.m. on July 24, 1993, power ascension was commenced following the repair of a steam leak on the 3B MSR drain line. In order to facilitate cleaning of the 3A TPCW heat exchanger, reactor power was stabilized at 50% at approximately 6:40 a.m. At 6:00 p.m., the licensee commenced a slow power increase and removed the 3B TPCW heat exchanger from service for cleaning. This heat exchanger was returned to service at 9:30 a.m. on July 25, 1993. Power ascension from 75% was re-commenced at a rate of 10% per hour, and 100% reactor power was achieved at 12:15 p.m. The inspectors witnessed portions of the power ascension.

b. At 1:15 a.m. on August 3, 1993, I&C personnel identified that the RC-1 relay in train B reactor protection relay rack QR37 was in the de-energized (fail safe) condition. With loop A RCS flows greater than 90%, the RC-1 and RC-2 relays should be energized. An investigation was initiated, and a replacement relay was found. At 5:35 a.m. the licensee closed reactor trip bypass breaker B in order to facilitate the replacement and testing of relay RC-1. This action placed Unit 3 in a 2-hour action statement per TS Table 3.3-1, item 19, Reactor Trip Breakers, action statement 8. This action statement requires that with the number of operable channels 1 less than the minimum channels operable requirement, the unit be in at least Hot Standby within 6 hours. This action statement also states that 1 channel may be bypassed for up to 2 hours for surveillance testing per TS 4.3.1.1 provided that the other channel is operable. The relay was replaced and tested per procedure 3-OSP-049.1, Reactor Protection System Logic Test; the B reactor trip bypass breaker was re-opened at 6:50 a.m.; the 2-hour action statement was exited.

c. On August 11, 1993, the licensee performed an operability assessment because pressurizer spray mini-flow bypass valve 4-524A was blowing steam out of a bellows rupture and body-to-bonnet O-ring leak, and an increase in leakage was noted from an inspection performed two weeks prior. The steam blowing out of the weep hole was impinging only on the insulation of spray valve PCV-4-455B which was located 12 inches overhead. The resulting steam condensation and boric acid crystal accumulation was being

deposited on the insulation or dripping directly onto the floor. There were no other components involved. The apparent rate of steam condensation on the overhead valve insulation was about 70 to 80 drops per minute, and the results of a leak rate calculation performed from 9:00 a.m. to 10:00 a.m. on August 11, 1993, were .08 gpm gross leakage and .03 gpm unidentified leakage. This was consistent with current and past leakage trends which were within TS limits. The leakage was minor in nature and was coming from a mechanical joint. Although any increase in the leakage would have been readily detectable by RCS leakrate calculations, R11/R12 levels, and sump level; licensee management elected to remove Unit 4 from service in order to facilitate the replacement of valve 4-524A. This action was conservative and was noted as a strength.

At 5:55 p.m. on August 12, 1993, a load reduction was commenced in order to facilitate the replacement of the pressurizer spray mini-flow bypass valve (4-524A) around pressurizer spray valve PCV-4-455B. Unit 4 was taken off line and entered Mode 2 at 8:34 p.m., and Mode 3 was entered at 8:44 p.m. On August 13, 1993, Unit 4 entered Modes 4 and 5 at 5:10 a.m. and 10:55 a.m., respectively. The inspectors attended many of the ERT meetings and followed up on the licensee's troubleshooting and planning activities.

Following the replacement of the mini-flow bypass valve, the RCS was filled and vented, a pressurizer bubble was established, and RCS heatup was commenced ahead of schedule. On August 15, 1993. Mode 4 was entered at 1:36 p.m., and Mode 3 was entered at 10:30 p.m. Normal operating pressure (2235 psig) and temperature (547°F) were established at 3:40 a.m. on August 16, 1993. Reactor startup was commenced at 4:22 p.m., Mode 2 was entered at 5:03 p.m., and criticality was achieved at 5:20 p.m. Mode 1 was entered at 7:55 p.m., Unit 4 was placed back on line at 9:27 p.m., and reactor power was increased to approximately 28% for a chemistry hold. The inspectors witnessed the licensee's approach to criticality. The evolution was performed in a professional manner with good communications.

d. At 3:42 p.m. on August 13, 1993, an I&C Specialist experienced respiratory problems while picking up his children at the licensee's Child Care Facility. Initial CPR was provided by individuals in the immediate vicinity. The site's medical group was called and responded in approximately three minutes. Metro-Dade was also called and arrived on site at 4:02 p.m. Metro-Dade transported the individual to South Miami Hospital of Homestead at 4:45 p.m., and the individual was declared dead at 5:20 p.m. Preliminary results indicated possible asthmatic bronchial spasms which may have led to cardiac arrest. The licensee notified the NRC Resident Inspector at 5:30 p.m., and notified the NRC Operations Center of a Significant Event per 10 CFR 50.72(b)(2)(vi) at 5:40 p.m. Because the fatality was not work-related, the licensee elected not to issue a press release, and the State of Florida was not notified. The NRC Resident Inspectors will followup on the

results of the autopsy and the licensee's investigation as they become available.

e. On August 13, 1993, the licensee identified a disconnected wire associated with the TDRL-X relay which had caused the cycle program in the OTΔT and OPΔT turbine runback logic to become dysfunctional. The TDRL-X relay normally sends a turbine runback signal to the governor for 1.5 seconds at a rate of 200% per minute every 30 seconds until the initiating signal clears. With the wire associated with TDRL-X disconnected, there would be no timing function, and the runback would occur continuously until the ΔT initiating condition clears. The OTΔT and OPΔT runback setpoint at Turkey Point is currently the same as the OTΔT and OPΔT reactor trip setpoints. Therefore, a turbine runback of any duration or frequency would be masked by the reactor trip.

The licensee identified the disconnected during a field walkdown to ensure similarity between the units in preparation of Unit 3 PC/M 93-005, Elimination of Turbine Runback on Dropped Rod. PC/M 92-181 had implemented this same modification on Unit 4 during the last refueling outage. The licensee had performed a 10 CFR 50.59 safety analysis of this modification.

A lack of attention to detail contributed to the problem in that the "before" drawings were not included in the PC/M in combination with the implementor not correctly interpreting the PC/M drawing. Additionally, with the TDRL-X relay outside the scope of the PMT, the problem went unnoticed. In order to address this issue, the licensee developed Condition Report No. 93-740.

As corrective action, the licensee plans to train appropriate personnel on the QI requirements with regard to "before" and "after" drawings in PC/M packages by approximately September 15, 1993, and on reading and interpretation of various electrical design and production drawings by approximately September 29, 1993. The licensee also plans to issue a TDI by approximately December 31, 1993, in order to clarify scope of PMT procedures. The cognizant design engineer will be directly involved with the preparation and performance of PMT procedures for complex tasks as determined by engineering.

The inspectors reviewed the licensee's interim disposition of Condition Report No. 93-740 and also verified that the OTΔT and OPΔT runbacks are not taken credit for in the accident analysis and, therefore, are not required by TSs. Additionally, with the runback setpoint the same as the trip setpoint, the runback as such serves minimal purpose. The inspectors noted a weakness in the lack of attention to detail on the Unit 4 design package for the elimination of the turbine runback on a dropped rod and noted a strength for engineering's quality perspective in the identification of the inadvertent removal of a wire on the Unit 4 turbine runback circuitry during the preparation for the

performance of the same modification on Unit 3. The inspectors will continue to monitor licensee performance in this area.

f. Unit 4 experienced a reactor trip from approximately 28% power at 10:33 p.m. on August 16, 1993. The reactor trip was caused by a turbine trip which was caused by high-high SG level (80% on narrow range) in the 4C SG. A feedwater oscillation during the evolution involving valving in of the 6A and 6B high pressure feedwater heaters located downstream of the main feedwater pumps resulted in the high SG level.

Unit 4 had been placed on line at approximately 9:27 p.m following the forced shutdown discussed in paragraph 8.c of this report. Power was increased and held at approximately 28% for secondary chemistry cleanup. SG level was appropriately being controlled with the feedwater flow control/regulation valves in automatic and one main feedwater pump in operation. With the 6A and 6B feedwater heaters still in bypass, the next step in the evolution was to place the two high pressure feedwater heaters in service. The ANPS for Unit 4 directed the NWE to place the feedwater heaters in service in accordance with procedure 4-OP-081.1, Feedwater Heater, Extraction Steam, Vents, and Drains Valve Alignment.

The NWE, along with a balance of plant non-licensed operator, simultaneously initiated section 7.8, Restoration of the 6A Feedwater Heater Tube Side, and section 7.9, Restoration of the 6B Feedwater Heater Tube Side, of procedure 4-OP-081.1. The sequence of steps to restore is specifically outlined in procedure 4-OP-081.1 with a sign-off following completion of each step.

For each heater, the 3-way heater bypass/normal valve is required by the procedure to be cracked open off the seat followed by verification of filling of the tube side of the heater. Then the tube side outlet valve is required to be slowly opened followed by the 3-way valve taken from the bypass to the normal position. Performing the steps in this sequence would minimize changes in feedwater flow to the SG. The inspectors noted that the procedure was silent on whether both the feedwater heaters can be valved in simultaneously.

Contrary to the steps outlined in procedure 4-OP-081.1, the two personnel performing the feedwater lineup first cracked open both the feedwater tube side outlet valves (4-30-123 and 4-30-223). Then they opened the 3-way feedwater heater normal/bypass valves (4-20-121 and 4-20-221) to the normal position. With the outlet valves only cracked open and the 3-way valves now in the normal position (i.e. feedwater flow through the heaters) the feedwater flow to the SGs started to drop as the running feedwater pump was essentially dead-heading.

The RCO observed the decreasing SG levels and was advised by the ANPS to start another condensate pump as well as the other main feedwater pump. The main feedwater flow control valves were also taken in manual with demand for full open. SG level recovered to approximately 25%.

The oncoming ANPS, who enroute to the control room had observed the NWE and the turbine operator open the 3-way valves, recognized the cause of the perturbation in the feedwater system. He requested the feedwater heaters to be unisolated. 6A feedwater heater was unisolated first by opening valve 4-20-223. Feedwater flow was recovered, and SG levels started to increase. The 4A feedwater pump was stopped, and attempts were made to reduce feedwater flow.

During this time, the 6A feedwater heater was also unisolated by opening valve 4-20-123. This caused feedwater flow to increase rapidly, and the RCO was unable to adequately control SG levels. The high-high level setpoint was reached on the 4C SG causing the turbine and consequently the reactor trip.

The post-trip response by the operators was as expected. The overfeeding of SGs caused Tave to go below the no load setpoint of 543°F. The cooldown was slowed by shutting the MSIVs. Letdown was manually isolated due to the decrease in pressurizer level caused by the cooldown. Additionally, AFW actuation had also occurred following the loss of both feedwater pumps due to the high-high SG level.

A notification pursuant to the requirements of 10 CFR 50.72 was made in a timely manner. The resident inspectors were also notified. The resident inspectors reviewed the Post Trip Review Restart Report and discussed the event with several key utility personnel including the Plant Manager. The resident inspectors expressed concern over the lack of command and control that resulted in the feedwater transient and subsequent reactor trip and the lack of good communications needed to ensure that both control room and field personnel were aware of the performance of significant evolutions. This was evidenced by the fact that the decision and the subsequent request by the ANPS to valve in the high pressure feedwater heaters was not properly communicated to the RCO. This resulted in the RCO not being fully aware of the activities that affected his ability to control SG levels. Concern over performing steps out of sequence was also discussed with the licensee.

The licensee was in full agreement with the concerns expressed by the resident inspectors. Corrective actions to prevent recurrence will include briefing control room supervisors as to the need for proper communication prior to initiation of major activities, counseling of the operators involved, and review for further enhancement to procedure 4-OP-081.1 in light of this event. The

licensee expects to complete these corrective actions by September 30, 1993. While the licensee's initial corrective actions were prompt and thorough, this violation is being cited because deficiencies in command, control, and communications allowed a procedural violation to escalate into a challenge to reactor safety and because a previous event also involved a procedural violation and a lack of proper communication between operators (VIO 50-250,251/93-01-02). The failure to follow steps as written in procedure 4-OP-081.1 will be tracked as VIO 50-250,251/93-21-01, failure to follow a procedure resulting in a feedwater transient and subsequent reactor trip.

The resident staff observed a majority of the activities associated with the reactor startup which was commenced at 9:17 a.m. on August 17, 1993. Criticality was achieved at 10:04 a.m., Mode 1 was entered at 1:01 p.m., Unit 4 was placed back on line at 1:28 p.m., and reactor power was stabilized at 100% at 6:00 a.m. on August 18, 1993, without any complications.

One Violation was identified.

9. 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 August 24, 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 |
|---|---|
| 50-250,251/93-21-01 | VIO - Failure to follow a procedure resulting in a feedwater transient and subsequent reactor trip (paragraph 8.f). |
| Strength | Management's decision to remove Unit 4 from service in order to facilitate the replacement of a pressurizer spray mini-flow bypass valve due to a minor unisolable leak was conservative (paragraph 8.c). |
| Weakness | The lack of attention to detail on the Unit 4 design package for the elimination of the turbine runback on a dropped rod (paragraph 8.e). |
| Strength | Engineering's quality perspective in the identification of the inadvertent removal of a wire on the Unit 4 turbine runback circuitry |

during the preparation for the performance of the same modification on Unit 3 (paragraph 8.e).

10. Acronyms and Abbreviations

| | |
|---|---|
| AFW | Auxiliary Feedwater |
| ANPS | Assistant Nuclear Plant Supervisor |
| CFR | Code of Federal Regulations |
| CPR | Cardiopulmonary Resuscitation |
| EDG | Emergency Diesel Generator |
| ERT | Event Response Team |
| F | Fahrenheit |
| GET | General Employee Training |
| gpm | Gallons Per Minute |
| I&C | Instrumentation and Control |
| LCO | Limiting Condition for Operation |
| LER | Licensee Event Report |
| MSIV | Main Steam Isolation Valve |
| MSR | Moisture Separator Reheater |
| NPS | Nuclear Plant Supervisor |
| NRC | Nuclear Regulatory Commission |
| NWE | Nuclear Watch Engineer |
| OP | Operating Procedure |
| OP$\Delta$T | Overpower Delta Temperature |
| OT$\Delta$T | Overtemperature Delta Temperature |
| OSP | Operations Surveillance Procedure |
| PC/M | Plant Change/Modification |
| PCV | Pressure Control Valve |
| PMT | Post-Modification Test |
| psig | pounds per square inch gauge |
| PTN | Project Turkey Nuclear |
| PWO | Plant Work Order |
| QA | Quality Assurance |
| QAO | Quality Assurance Organization |
| QC | Quality Control |
| QI | Quality Instruction |
| QP | Quality Procedure |
| RCO | Reactor Control Operator |
| RCS | Reactor Coolant System |
| SG | Steam Generator |
| SMI | Surveillance Maintenance - I&C |
| Tave | Average Temperature |
| TDI | Technical Department Instruction |
| TPCW | Turbine Plant Cooling Water |
| TQR | Topical Quality Report |
| TS | Technical Specification |
| VIO | Violation |
| $\Delta$T | Delta Temperature |