UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30303

JUL 05 1984

Report No.: 50-251/84-21

Licensee: Florida Power and Light Company
9250 West Flagler Street
Miami, FL 33101

Docket No.: 50-251

License No.: DPR-41

Facility Name: Turkey Point 4

Inspection Date: June 4-6, 1984

Inspection at Turkey Point site near Homestead, Florida

Inspector: D. P. Falconer — 7-2-84
D. P. Falconer — Date Signed

Accompanying Personnel: T. Peebles, Resident Inspector

Approved by: H. E. P. Krug — 2 JUL 84
H. E. P. Krug, Acting Section Chief — Date Signed
Operational Programs Section
Division of Reactor Safety

SUMMARY

Areas Inspected:

This special unannounced inspection involved 20 inspector-hours on site in the area of event followup.

Results:

In the area inspected, one apparent violation was found (Failure to follow plant procedure for temporary system alteration, paragraph 5.f, (Violation 251/84-21-04)). Also identified were: Inspector Followup Item 251/84-21-01, "LP Heater bypass valve closing stroke time"; Inspector Followup Item 251/84-21-02, "Turbine runback setpoint"; Inspector Followup Item 251/84-21-03; "Procedure for automatically cycling pressurizer spray valves"; Inspector Followup Item 251/84-251-05; "DDPS upgrade" and Inspector Followup Item 251/84-21-06; "Steam dumps failure to actuate."

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REPORT DETAILS

1. Persons Contacted

   *K. Harris, Manager, Operations
   *C. Baker, Plant Manager, Nuclear
   *D. Grandage, Operations Superintendent, Acting
   *J. Labarraque, Technical Department Supervisor
   *E. Hayes, I&C Supervisor, Acting
   *J. Arias, Regulation & Compliance Lead Engineer
   *F. Houltz, Quality Control
   *W. Bradon, Quality Assurance

   Other licensee employees contacted included operators and staff engineers.

   NRC Resident Inspector

   *T. Peebles

   *Attended exit interview.

2. Exit Interview

   The inspection scope and findings were summarized on June 6, 1984 with those persons indicated in paragraph 1 above. The licensee acknowledged the inspection findings.

3. Licensee Action on Previous Enforcement Matters

   Not inspected.

4. Unresolved Items

   Unresolved items were not identified during this inspection.

5. Unit 4 Reactor Trip

   On June 4, 1984, at 1:21 a.m., Turkey Point Unit 4 experienced a reactor trip. The exact cause of the reactor trip could not be determined due to the possible loss and inaccuracy of sequence of event information logged by the plant Digital Data Processing System (DDPS).

   The inspector observed and evaluated the licensee post trip review process. The inspector attended the Plant Nuclear Safety Committee meeting during which the results of post trip review were evaluated prior to unit restart. NRC Region II concurred with the restart decision at approximately 11:00 p.m. on June 4, and restart was immediately authorized by licensee management.

a. Sequence of Events

The unit was operating at 100 percent power with two condensate pumps and the 'B' Heater Drain Pump (HDP) operating. The Steam Generator Feedwater pumps (SGFP) were experiencing lower than normal suction pressure and the Low Pressure (LP) Feedwater Heater Bypass valve had opened. In response to the low suction pressure, the 'A' HDP was started and the LP Feedwater Heater Bypass valve was manually closed. Upon closure of the bypass valve, SGFP suction pressure began to decrease and the 'A' SGFP tripped on low suction pressure.

A turbine runback to 70 percent power was initiated on the SGFP trip. Pressurizer spray valves failed to automatically open on the RCS pressure increase and operators manually initiated pressurizer spray.

The reactor tripped during the turbine runback. The first out annunciator indicated that the reactor had tripped on steam flow greater than feed flow coincident with a low S/G level. During the transient, one or more S/G code safeties lifted as designed, the atmospheric steam dumps opened and the '6B' feedwater heater relief valve lifted. Steam dump valves to the condenser did not actuate as they should have. Auxiliary feedwater actuated on low-low S/G level. The unit was stabilized and the Main Steam Isolation valves closed. Restart was not begun until proper authorization was granted.

b. Transient Analysis

T-avg spiked to a high of 584°F during the runback and subsequently decreased to approximately 537°F 170 seconds after the reactor trip as a result of S/G code safety actuation, atmospheric steam dumps opening, the "6B" feed heater relief valve lifting and cold auxiliary feedwater addition.

Pressurizer level trended T-avg as expected. Level peaked at approximately 67 percent and decreased to approximately 11 percent, 170 seconds after the reactor trip.

RCS pressure increased to approximately 2329 psig, then decreased and stabilized at 2264 psig during the runback. After the reactor trip, RCS pressure decreased to a low of 1730 psig due to excessive secondary side steam relief.

c. Low SGFP Suction Pressure

The secondary side pressure transient that resulted in the trip of the 'A' SGFP was initiated when operators closed the LP feedwater heater bypass valve. In addition, earlier problems encountered with HDT level control and HDP operation contributed to lower than normal SGFP suction pressures existing prior to the turbine runback. Considering the lower than normal SGFP suction pressures that existed, starting the third condensate pump prior to making feedwater flow manipulations would have minimized possible secondary side transients. The inspector informed the licensee that operation of the third condensate pump in similar situations was a good operational practice. The licensee concurred.

The specific reason for the low suction pressure trip of the 'A' SGFP has been attributed to the rapid closure of the LP heater bypass valve causing a momentary low SGFP suction pressure. The licensee committed to evaluate the adjustment of the LP heater bypass valve closing stroke time to minimize its effect on SGFP suction header pressures. Evaluation of the stroke time adjustment will be identified as inspector followup item 251/84-21-01.

d. Turbine Runback Setpoint

Presently, the setpoint for turbine runback on loss of one SGFP is 70 percent power; while the full capacity of one feedwater pump is only 60 percent flow. This difference makes a successful runback on loss of a SGFP unlikely. The licensee has performed a runback study and has concluded that the runback setpoint requires adjustment. The licensee committed to implement the identified change to the runback setpoint by June 15, 1984. Implementation of the setpoint change will be identified as inspector follow up item 251/84-21-02.

e. Pressurizer Spray Valves

During the runback, RCS pressure increased to 2329 psig. This is above the automatic initiation setpoint for pressurizer spray; however, the spray valves failed to open automatically. Operators were able to manually open the valves and initiate pressurizer spray and terminate the RCS pressure increase.

Post trip calibration checks revealed no problems. Failure of the spray valves to open has been attributed to their sticking, due to extended periods of nonoperation.

The licensee committed to procedurally require automatic cycling of the spray valves once per day by turning on the pressurize heaters and allowing the valves to cycle. Implementation of the procedural requirement will be identified as Inspector Followup Item 251/84-21-03.

f. Pressurizer Safety Valve Tail Pipe Temperature

During the transient, operators observed temperature indicator TI-4-467 to read 350°F. This indicator is on the tailpipe of the 'B' pressurizer code safety and generated concern that the safety may have lifted during the transient. Post trip investigation revealed that the valve had not lifted but that the indicator had failed due to a circuit padding resistor failure inside containment. Pressurizer relief tank (PRT) pressures and temperatures and the acoustic flow monitor indication support this conclusion.

During the investigation of the TI-4-467 circuit, it was found that the padding resistor for TI-4-465 had been moved outside of containment during the refueling outage. Although the movement of the padding resistor in the TI-4-465 circuit constituted a temporary modification, no temporary change tags or documentation supporting the temporary change existed.

Contrary to Administrative Procedure 0103.3, Control and Use of Temporary System Alterations, movement of the padding resistor for TI-4-465 was not documented as a temporary system modification. This is a violation (251/84-21-04).

g. Digital Data Processing System (DDPS)

Operators observed the first out annunciator to be steam flow greater than feed flow coincident with low S/G level, however the DDPS printout indicated that the trip was initiated by the opening of the 'A' reactor trip breaker (RTB). The DDPS printout had no indication of steam generator reactor trip matrix actuation.

Because of discrepancies identified in the DDPS printout, the licensee postulates that the DDPS overloaded due to excessive and rapid data inputs during the transient.

The present DDPS printer is outdated and its speed appears to be the most limiting factor on buffer output speed, and as such contributes to the probability of buffer overloads during complex and rapidly occurring events. The licensee committed to evaluate the installation of modern high speed printer for the DDPS.

Post trip investigation of DDPS inputs from the reactor trip racks identified several trip relays that would not give a DDPS printout. The identified relays functioned correctly in their protective capacity, but did not input correctly to the DDPS. The licensee committed to procedurally checking for correct DDPS input during logic functional testing.

If at anytime, the event buffer of the DDPS contains more than 10 entries from an input, that channel will be inhibited. The purpose of this inhibit is to prevent relay chattering from filling the buffer. An input may also be inhibited by operator command. Once suppressed by either automatic inhibit or operator command it can only be returned by operator command. This feature of the DDPS could potentially delete important post trip information. The licensee committed to procedurally checking the status of DDPS inhibits once per day to prevent the possible loss of post trip information.

Pending evaluation of a high speed printer and implementation of the procedural checks identified above, this item will be identified as Inspector Followup Item 251/84-21-05.

h. '6B' Feedwater Heater Relief Valve

The '6B' feedwater heater relief valve lifted during the trip transient and contributed to the excessive RCS cooldown. The relief valve lifted when the moisture separator steam supply valve (MOV 1433) failed to close due to a malfunctioned limit switch. Main steam fed through the failed open MOV 1433 to the MSR to the reheater drain tank up through manually open valve CV1506 to the 6B feedwater heater and lifted the relief valve. The licensee repaired the valve prior to unit restart.

i. Steam Dump Valves

The steam dumps to the condenser failed to actuate during the reactor trip. The licensee is evaluating this failure. This will be identified as Inspector Followup Item 251/84-21-06.

j. Post Trip Review

The licensee performed an in depth post trip review in an effort to identify the causes of the trip and identify necessary corrective actions. The exact cause of the reactor trip could not be determined due to conflicting information between operator observations and the sequence of events printout. As a result, the licensee postulated the possible trips that could bound the post trip data and instituted actions to address each scenario identified.

Listed below are the postulated scenarios and corrective actions addressed prior to unit restart.

(1) Assumption: The DDPS printout is correct and the 'A' RTB opened initiating a turbine trip which deenergized Reactor Trip relays 9 and 10 and opened the 'B' RTB.

The only means of opening the trip breaker are energizing the shunt trip, deenergying the UV trip coils or use of the manual pushbutton on the breaker. The first two were ruled out because the DDPS did not indicate actuation of the trip device. Use of the manual push button was ruled out because security records did not show anyone in the room at the time of the trip.

The 'A' RTB was tested using the approved maintenance procedures. Physical vibration of the breaker was attempted to check if loose wires or intermittent open could have tripped the breaker. No abnormalities were found.

The 'A' breaker was replaced with the spare RTB. Both the 'A' and 'B' RTB's were tested prior to restart.

(2) Assumption: Operators correctly observed the first out annunciator and the DDPS did not correctly log trip actuation due to input overload.

The licensee thoroughly checked the DDPS. Several relays were identified that did not properly input to the DDPS. The licensee found that the malfunctions were the result of dirty contacts. The licensee cleaned the contacts and verified relay operability prior to restart. The licensee performed the steam generator level periodic test. No abnormalities were found.

This is the expected trip for the transient that occurred. Failure to identify a problem with the 'A' RTB and observation of first out annunciator led the licensee to postulate that this was the most probable scenario, although the DDPS did not provide supporting data. DDPS design information indicates that buffer overloads would cause DDPS event timing inaccuracies and result in lost data. Corrective actions were identified in Paragraph 5g above.