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FACIL:50-250 Turkey Point Plant, Unit 3, Florida Power and Light C 05000250

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SUBJECT: LER 98-001-00:on 980216,manual reactor trip occurred due to loss of turbine control oil pressure w/steam leak in auxiliary feedwater steam supply piping.Auxiliary governor maint instructions will be revised.W/980318 ltr.

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L-98-053
10 CFR 50.73

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D. C. 20555

Re: Turkey Point Units 3 and 4
Docket Nos. 50-250, 50-251
Reportable Event: 98-001
Date of Event: February 16, 1998
Manual Reactor Trip due to Loss of Turbine Control Oil Pressure, With Steam Leak in Auxiliary Feedwater Steam Supply Piping

The attached Licensee Event Report is being submitted pursuant to the requirements of 10 CFR 50.73 to provide notification of the subject event.

Sincerely,

R. J. Hovey
Vice President
Turkey Point Plant

CLM

Attachment

cc: Regional Administrator, USNRC Region II
Senior Resident Inspector, USNRC, Turkey Point Plant

IE22

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
TURKEY POINT UNIT 3	05000250	1 OF 10

TITLE (4) Manual Reactor Trip due to Loss of Turbine Control Oil Pressure, With Steam Leak in Auxiliary Feedwater Steam Supply Piping

EVENT DATE (5)			LER NUMBER (6)			RPT DATE (7)			OTHER FACILITIES INV. (8)	
MON	DAY	YR	YR	SEQ #	R#	MON	DAY	YR	FACILITY NAMES	DOCKET # (S)
02	16	98	98	001	00	03	18	98	TURKEY POINT UNIT 4	05000251

OPERATING MODE (9)	1/1	10 CFR 50.73(a)(2)(iv)
POWER LEVEL (10)	100/100	

LICENSEE CONTACT FOR THIS LER (12)

	TELEPHONE NUMBER
C. L. Mowrey, Compliance Specialist	305-246-6204

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	EPIX?	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	EPIX?
A	TG	65	W120	Y					

SUPPLEMENTAL REPORT EXPECTED (14) NO ☒ YES ☐	EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
(if yes, complete EXPECTED SUBMISSION DATE)				

ABSTRACT (16)

At 0438 hours, the Unit 3 turbine intercept and control valves closed due to a loss of turbine control oil pressure. The reactor was manually tripped subsequent to high steam flow alarms, automatic control rod insertion, and loss of turbine load. Auxiliary Feedwater (AFW) automatically initiated due to low steam generator levels. The Main Steam Isolation Valves were manually closed to control Reactor Coolant System temperature. The loss of control oil pressure was due to a test lever in the turbine auxiliary governor which was overly sensitive to very small movement. Apparently the lever was inadvertently bumped during nearby maintenance. The sensitive test lever was removed.

Following the reactor trip a secondary side steam leak occurred. The steam leak was from a two inch drain line that branched off the 4 inch Train 2 AFW steam supply line. Despite the steam leak, the AFW system provided adequate feedwater flow to the steam generators for the duration of the event. To isolate the steam leak, AFW Train 2 was secured. The steam leak was due to outside diameter (OD) corrosion resulting from water trapped under insulation next to a support. The AFW piping susceptible to OD corrosion was inspected. About 50 feet of AFW steam drain piping was replaced, and both units' AFW steam piping was pressure tested.

I. DESCRIPTION OF THE EVENT

On February 16, 1998, Florida Power & Light (FPL) Company's Turkey Point Unit 3 was operating in Mode 1 at 100% power. At 0438 hours, the Unit 3 turbine intercept and control valves [SB:fcv] closed due to a loss of turbine control oil pressure. Seven seconds later, the reactor was manually tripped subsequent to high steam flow alarms, automatic control rod insertion, and a loss of turbine load.

During the event, both pressurizer Power Operated Relief Valves (PORVs)[AB:rv] momentarily cycled, as expected for a loss of secondary load. Auxiliary Feedwater (AFW)[BA] automatically initiated due to low steam generator levels. The Main Steam Isolation Valves (MSIVs)[SB:isv] were manually closed to control Reactor Coolant System (RCS)[AB] temperature.

Following the reactor trip a secondary steam leak occurred. The steam leak was from a two inch drain line piping upstream of steam trap ST-050, that branches off the four inch Train 2 AFW steam supply line.

After the MSIVs were closed and main feedwater was isolated, the steam leak persisted, prompting the Nuclear Plant Supervisor (NPS, acting as the Emergency Coordinator) to declare an Unusual Event. The NRC Operations Center (NRCOC) was notified of the trip and Unusual Event at 0525, in accordance with 10 CFR 50.72. The steam leak was stopped after Train 2 AFW was secured and isolated at 0600; at 0620 the Unusual Event was terminated, and at 0637 the NRCOC was notified. An Event Response Team was formed to investigate the causes for the loss of turbine control oil pressure and the steam leak.

Other than paint removal and minor surface erosion of adjacent concrete, the steam impingement from the leak did not adversely affect plant components, and did not result in any personnel injuries.

A chronology of events surrounding the reactor trip and steam leak follows:

TIME	EVENT DESCRIPTION
04:38:02.09	Turbine Intercept and Control Valves close due to loss of Turbine control oil pressure.
04:38:08.90	Unit 3 Reactor Control Operator manually trips Reactor due to high steam flow annunciators, automatic control rod insertion, and loss of load.
04:38:12	PCV-3-455C AND PCV-3-456 automatically opened due to high pressurizer pressure.
04:38:21	PCV-3-455C AND PCV-3-456 automatically closed.
04:38:42.35	Steam Generator B Low-Low Level Reactor Trip actuated.
04:39:18	Auxiliary Feedwater flow automatically established due to Low Low Steam Generator Levels.
04:39:18.75	MSIVs manually closed to control Tavg decrease.

04:45	Steam noise from secondary system noted. Nuclear Watch Engineer (NWE) dispatched to investigate.
04:46	NWE reports steam coming from vicinity of condensate pit. Feed and Condensate trains were secured per Assistant NPS direction.
04:47	Unusual Event declared on Unit 3 at Emergency Coordinator discretion.
04:53	Suspected steam break to be from Unit 4 Auxiliary Steam. Closed isolation valves 4-10-078 and 4-10-007.
05:00	Placed Control Room ventilation on RECIRC due to high humidity.
05:03	Entered 3-GOP-103. Steam leak still apparent. Suspected AFW Train 2 steam line. Personnel unable to get close enough to determine location of leak.
05:25	NRCOC notified of trip and steam leak.
05:52	Started 'A' Standby Steam Generator Feed Pump.
06:00	Secured Train 2 AFW and stopped 'B' and 'C' AFW pumps. Noticed steam leak noise diminish.
06:35	Placed turbine on turning gear.
06:20	Exited Unusual Event (UE).
06:37	NRCOC notified of UE termination.

II. CAUSE OF THE EVENT

Loss of Turbine Control Oil Pressure

The Turbine Control System [TG] consists of several subsystems that are hydraulically connected through a series of orifices. One of the subsystems is control oil. The turbine control oil is used to hold open the low pressure intercept valves and to sequentially open the control valves. The control oil pressure is increased proportionally to control speed/turbine load through the use of the governor and the load limit. The auxiliary governor [TG:65] will protect the turbine from overspeed by reducing control oil pressure during a fast speed increase (rate of change of 3%/sec) at 102% of rated speed condition, or if internal auxiliary governor oil pressure decreases to approximately 20 psig (108% of rated speed), the auxiliary governor will dump control oil to the intercept and turbine control valves for 2-5 seconds. Either of these actuations will produce a loss of control oil pressure.

A review of the data collected by the Event Response Team revealed that the initiating event was the loss of control oil pressure. With the loss of control oil pressure, the control valves and intercept valves went closed. This was recognized by operators as a loss of load and the reactor was manually tripped. Following the original loss of pressure, an increase in control oil pressure occurred approximately 6 seconds later. This is

consistent with the operation of the auxiliary governor which will dump control oil pressure for approximately 2-5 seconds and then re-establish pressure. Approximately 7 seconds after the original loss of control oil pressure, the reactor was manually tripped which dumped control oil through the solenoid valves and the governor emergency trip valve. The apparent cause of the trip was the actuation of the auxiliary governor. Trouble shooting plans were developed to check the turbine controls that could cause a sudden rapid loss of control oil pressure.

Initial investigations that involved re-latching the turbine control system to attempt to identify a failed component could not replicate the problem. All control functions operated within design parameters when the turbine valves were stroked using the normal valve surveillance procedures. The individual components were then disassembled and inspected to attempt to identify any failed or bad components. No items were observed that could explain the loss of control oil pressure. The controls were then reassembled and tested in accordance with the normal work controls. Post assembly testing did not initially reveal any abnormalities; however, when securing from the last test of the auxiliary governor investigators noted that a slight jarring of the test lever would cause a significant change in auxiliary governor oil pressure to the point of actuating the auxiliary governor. The lever was properly locked down and should have been insensitive to any jarring or vibration.

The test valve plunger was then removed and detailed measurements were taken. These measurements revealed that the lever stop at the rear of the plunger (which prevents the plunger from excessive withdrawal) was causing the plunger to be inserted to the seated position. The seating of the plunger was restricting impeller oil supply to the bellows of the auxiliary governor. The test valve lever stop was observed to have a stiffener block mounted on the inside of the bracket which restricts the amount of withdrawal of the test valve. Inspection of the Unit 4 test lever revealed that spacers were installed on the test lever stop that increased the withdrawal distance of the test lever plunger. The lack of spacers on the Unit 3 device made it sensitive to jarring. Spacers were installed to ensure that the test plunger was not seated. The device was checked to ensure there was no tendency to actuate due to jarring or slight movement of the test lever.

Even though the device was sensitive to jarring it still had to be jarred or touched. Operations and Maintenance personnel were interviewed to determine if anyone was in the area at the time of the trip. The interviews revealed that Maintenance personnel were at the turbine front standard with the door to the controls area open, to inspect for a burned out light above the door. Inspection of the area layout and overhead light position revealed that inadvertent bumping of the test lever during this activity could occur. This is believed to be the initiating event which caused the auxiliary governor actuation and the loss of control oil pressure.

After further review to determine when the stiffener block was added to the test valve lever stop, FPL discovered on March 9, 1998, that Plant Change/Modification (PC/M) 74-99 had modified the auxiliary governor test valve to limit the test valve's stroke (implemented in response to Westinghouse Power Generation Service Program 74-8 dated May 16, 1974). The modification included drilling a 1/8 inch hole in the test valve plunger, making the ½ inch stiffener block and tack welding it to the lever stop, and installing a locking mechanism to limit the test valve travel to 1/4 inch. The inspection performed on February 18, 1998, revealed that the test valve plunger did not have the 1/8 inch hole as per PC/M 74-99. This configuration (test valve fully seated without 1/8 inch hole) effectively made the test handle sensitive to slight movement in a side to side manner. Movement from left to right was confirmed to actuate the auxiliary governor when the conditions that existed at the time of the trip were recreated. The FPL spare part stocked is Westinghouse part # 493C763005 and was replaced during the last refueling outage. This Westinghouse part number corresponds to the original test valve plunger without the modification (1/8 inch diameter hole) of PC/M 74-99. A new replacement part number was not generated for the modified test valve plunger after implementation of PC/M 74-99. On February 18, 1998, in order to unseat the Unit 3 test valve plunger, spacers were installed to ensure that the test valve was unseated. Unseating of the test valve plunger provided the same relieving action as the 1/8 inch hole.

The root cause of the loss of control oil pressure was personnel error by non-licensed utility personnel in the 1974 time frame, in two respects:

1. The replacement part number to be used for the test valve plunger after the implementation of PC/M 74-99 was not updated. This part discrepancy allowed the wrong part to be used during subsequent maintenance to the auxiliary governor. Therefore, an incorrect replacement part was used after auxiliary governor test valve modification.

2. The work control documents (maintenance instructions/vendor manual) for the auxiliary governor were not updated after the implementation of PC/M 74-99, to ensure the proper test valve plunger was used, i.e., a test valve plunger with a 1/8 inch diameter hole. The use of the test valve plunger without the relieving 1/8 inch hole made the test lever sensitive to minor bumping.

- AFW Train 2 Steam Leak

The leak was discovered in a two inch, Schedule 80, plain carbon steel pipe (A106, Grade B). The affected pipe is the branch line to steam trap ST-50, off of the AFW Train 2 steam supply piping. It was covered with 2½ inch thick calcium silicate insulation with aluminum lagging. This section of pipe is exposed to weather (The Turkey Point turbine building is not enclosed).

The failure consisted of a blown-out pipe section which measured approximately 3 inches long and circumferentially from the 7 o'clock to the 12 o'clock position. It was located in a horizontal section, immediately downstream from a two inch wide pipe strap. The fracture surface varied in thickness from approximately 0.047 inch to 0.160 inch. Portions of the remaining pipe adjacent to the fracture surface were plastically deformed outward, indicating that it was a high energy failure.

The pipe displayed evidence of external corrosion under, and immediately adjacent to, the pipe strap. The corrosion products were tightly compressed and tenacious within the pipe strap region. Those in the adjacent regions were more voluminous and loosely adherent.

Several potential root causes were postulated for the piping wall failure in the steam trap header line. Flow accelerated corrosion, overstress/support adequacy, material defects, and construction-induced defects were eliminated. The root cause was determined to be external corrosion, as discussed below.

The subject steam trap branch line is normally isolated and is only exposed to steam pressure and temperature during AFW operation. As such, the line is normally cold; any water which collects within the insulation could remain in

contact with the pipe for extended periods of time. On other steam lines or steam trap lines which are normally in service, any water collected within the insulation would quickly evaporate, eliminating extended water contact with the piping. In general, support locations or system components, e.g., valves, could act as dams within the insulation to retain water or could provide entry points for water. Once the water entered the insulation, it could remain in contact with the piping for an extended period, causing both general and localized piping corrosion.

The remaining calcium silicate insulation installed on the ST-50 inlet piping was removed and ultrasonic test (UT) readings were taken on the exposed piping. Visual inspections and UT readings were also performed on the two other strap locations in the horizontal section, downstream of the failure. Both displayed evidence of external corrosion. Similarly, a vertically oriented section downstream of the failure also displayed evidence of external corrosion in the vicinity of a strap.

These observations indicated that the initiating failure mechanism of the subject piping was outside diameter initiated corrosion. This corrosion likely resulted from the collection of water in the strap region due to openings in the thermal insulation. Since AFW is a standby system, and therefore at ambient temperature most of the time, water collected would remain on the pipe until steam was admitted to the system.

III. ANALYSIS OF THE EVENT

Three quick starting, steam turbine driven, auxiliary feedwater pumps are provided for Turkey Point Units 3 and 4. The three pumps are installed in a shared system arrangement, such that each pump can supply auxiliary feedwater to Unit 3 and/or 4. Two pumps (B and C) are normally aligned to AFW Train 2 and the third pump (A) is normally aligned to AFW Train 1. The pumps can continue to supply reduced amounts of water to the steam generators until steam pressure is reduced to 85 psig. The pump output in pounds per hour is greater than the steam consumption until the 85 psig point is reached. However, at 120 psig, the Residual Heat Removal (RHR)[BP] System is started and the AFW pumps are shut down.

A calculation has been performed to determine AFW pump turbine operability at or near RHR entry conditions. Based on the sizing requirements of the condensate storage tank provided in UFSAR Section 9.11.2, it is assumed the unit would reach RHR entry conditions, where AFW would be secured, about 19 hours after unit trip. RHR would be started with the RCS at 350°F and less than 450 psig. The calculation demonstrated that sufficient steam would reach the AFW turbine inlet to allow it to operate properly, even with the leak in the steam trap piping in question, to permit shutdown and subsequent unit cooldown to the point at which RHR would be initiated.

This calculation is very conservative. Operations would follow plant procedures, which would lead to efforts to restore off site power. Restoration of offsite power results in availability of the main feedwater and electric driven standby feedwater pumps, and thereby reduces the impact of a loss of an AFW train. Availability of offsite power also permits reactor coolant pump operation, which enhances RCS pressure control. Concurrently, off normal operating procedures would lead operations personnel to provide feedwater from one of the available non safety feedwater pumps (main, electric driven standby feedwater pump or diesel driven standby feedwater pump) in the event the AFW steam supply piping is leaking, which was the case.

The Updated Final Safety Analysis Report (UFSAR) discusses the expected plant response to a complete loss of generator load, and shows the adequacy of the pressure relieving devices and that no core damage results. The UFSAR assumes a complete loss of load without a direct reactor trip, i.e., the turbine is assumed to trip without actuating the sensors for reactor trip on the turbine stop valves. With this assumption, reactor trip is delayed until conditions in the RCS cause a reactor trip. The UFSAR concludes that this event poses no hazard to the integrity of the RCS or steam system. The event reported herein differs from the analyzed event, in that (1) the reactor was manually tripped before any automatic trip signal was generated, and (2) a turbine trip signal was not generated, since only turbine control oil pressure was lost, not turbine autostop oil pressure.

The UFSAR analysis bounds the trip which occurred in this case. Plant procedures provide operator guidance in responding to these transient conditions, and in assuring that the plant is stabilized in a safe condition. Following the manual trip, the unit was stabilized in Mode 3 in accordance with these approved plant procedures. Despite the steam leak, the AFW system provided adequate feedwater flow to the steam generators for the duration of the event. Until Train 2 of AFW was isolated, 4500 seconds into the transient, it provided ample AFW flow to all three steam generators. Therefore the health and safety of the public were not adversely affected.

The UFSAR also discusses a loss of normal feedwater to all steam generators due to loss of the steam generator feed pumps, valve malfunction, or Loss of Offsite Power (LOOP). The analysis shows that following a loss of normal feedwater, the AFW system is capable of removing the reactor's stored and residual heat assuming that only one AFW pump is available. Since both AFW trains were operating for the first 4500 seconds of the event, and AFW Train 1 was available for the duration of the event, the event is bounded by the UFSAR analysis.

The Unit 3 event that resulted in the leak in the steam trap line occurred without any single failures or a LOOP. Within the licensing basis, both a LOOP and a single failure would be credible. Response to a reactor trip with LOOP would result in a natural circulation cooldown and would prevent the use of the main feedwater pumps or electric-driven standby feedwater pump [SJ:p] to provide feedwater. In such an event, the diesel-driven standby feedwater pump would have been available. For the event that occurred, a single failure of AFW Train 1 (AFW Pump A) would result in the need to rely on the faulted Train 2 steam supply. This supply was demonstrated to be sufficient at normal RCS temperature and pressure conditions.

Probabilistic Safety Assessment

A Probabilistic Safety Assessment (PSA) has been performed both on the unit that tripped and sustained the steam supply piping break, and on the unit that continued to operate. Because Train 2 of AFW actually operated, and has been demonstrated by calculation to remain operable, partial credit for AFW Train 2 was made in the PSA for the unit that tripped. The conditional core damage probability (that the trip on Unit 3 would have proceeded to core damage) has been calculated to be less than 1.0 E-6, assuming no Anticipated Trip Without Scram (ATWS). For Unit 4, the PSA was performed assuming that AFW Train 2 was out of service for 72 hours. The core damage probability increase for 72 hours was conservatively estimated at 3.0 E-8, with credit taken for realignment of an AFW pump to Train 1.

IV. CORRECTIVE ACTIONS

Loss of Control Oil Pressure and Reactor Trip

1. Unit 3 was stabilized in Mode 3 following the trip, until the causes of the loss of control oil pressure and the steam leak were determined and corrected.

2. The clearances on the Unit 3 auxiliary governor test plunger were re-established by the addition of spacers that ensured the test valve's full withdrawal. The handle was then removed and a through bolt was installed in the auxiliary governor test valve lever stop to lock the test valve in place. The lever was then tested to ensure that there was no tendency to actuate due to jarring or slight movement of the lever.

3. Signs were installed around the area of the Unit 3 and Unit 4 front pedestals warning personnel of trip sensitive equipment and to notify the NPS prior to performing any work near any of the control system components.

4. FPL will review other Westinghouse Service Bulletins for applicability of replacement parts due to implementation.

5. The auxiliary governor maintenance instructions will be revised to include verification of the proper test valve plunger to be used.

6. The Condition Report database was reviewed for any similar inadequate plant change implementations involving replacement parts. There were no indications of replacement parts not being updated after implementation of modifications.

7. FPL will inspect, and replace as necessary, the auxiliary governor test valve plungers on both Units 3 and 4.

8. FPL will update the spare part information to include the correct part number for the auxiliary governor test valve plunger. Turkey Point's spare test valve plungers will be modified in accordance with PC/M 74-99, to drill a 1/8 inch diameter hole in the test valve plunger.

9. FPL will update the vendor manual to include the auxiliary governor test valve modification of PC/M 74-99.

10. Engineering processes have been significantly strengthened since PC/M 74-99 was implemented. The PC/M process now requires that Engineering identify new spare parts, disposition existing spare parts, and update vendor manuals.

AFW Steam Pipe Break

11. FPL performed a review of the steam lines associated with the AFW system to address generic implications. This review focused on that piping considered to be susceptible to the OD originated corrosion phenomena

identified on the steam trap line. In general, susceptible piping was defined by several factors including the following:

- Piping downstream of the steam supply MOV's (MOV-*-1403/4/5) which is normally isolated. Such piping would not be at elevated temperatures and would allow the collection and retention of water within the insulation for extended periods of time.

- Disruption points in the insulation system which have vertical (upward) or horizontal openings that create the potential for water intrusion. Typically such disruptions are associated with either pipe supports or system components.

- Sections of the system exposed to typical weather conditions such that normal rain, etc. would provide a repetitive source of wetting.

Utilizing this criteria, the existing steam supply lines, including branch lines, for both trains and both units were walked down and assessed for additional inspection requirements.

12. Six branch connections, including four steam trap lines on Train 2, one vent line on Train 2, and one steam trap line on Train 1, met the criteria described above. All six were inspected. Two of the Train 2 steam traps were in sheltered areas to confirm the adequacy of the original inspection plan. The remaining four selections encompassed all exposed locations. The two exposed Train 2 traps required both piping and support component replacements due to external corrosion. All other locations showed no evidence of significant external corrosion.

13. All exposed supports, including the adjacent piping, on the four inch steam supply header that were considered to be susceptible were inspected and found to meet design requirements. Some support components were replaced due to corrosion. While adjacent piping showed evidence of external corrosion, all piping was determined to be acceptable for continued operation.

14. The AFW steam supply piping (Trains 1 and 2 including steam trap branch lines) were pressurized for four hours and inspected. The results of the pressure tests confirmed no additional steam leaks were present.

15. In order to address applicability to other safety related systems, FPL performed a preliminary review based on the failure mode. The affected piping is uncoated; insulated; normally at low temperature; susceptible to the corrosion mechanism, e.g., carbon steel; and in a location that is exposed to typical weather conditions such that normal rain, etc., would provide a repetitive source of wetting. No other safety related systems were identified that met these criteria.

16. FPL is evaluating additional actions to prevent recurrence in the long term such as removal of unnecessary insulation, protective coatings on affected piping, and/or an inspection program.

V. ADDITIONAL INFORMATION

Licensee Event Report 251/97-002, dated 5/22/97, reported an automatic reactor trip due to loss of electrical load. The reactor operator observed several high steam flow alarms. The alarms were the result of inadvertent actuation of the turbine overspeed protection circuit causing the control and intercept valves to throttle close. The reduction in heat removal from the RCS via the main steam / turbine systems resulted in a reactor trip on OTΔT. The loss of external load resulted in opening the Pressurizer PORV's and lifting each Main Steam Safety Valve set at 1085 psig (lowest setting).

Licensee Event Report 251/93-002, dated 7/22/93, reported a reactor trip due to a manual turbine trip. In that event the root cause was determined to be an inadvertent actuation of the auxiliary governor trip lever.

EIIS Codes are shown in the format [EIIS SYSTEM: IEEE component function identifier, second component identifier (if appropriate)].