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

Report Nos.: 50-250/86-50 and 50-251/86-50

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 3 and 4

Inspection Conducted: December 15, 1986 - January 12, 1987

Inspectors: B.A. Wilson for 2/3/87
D. R. Brewer, Senior Resident Inspector Date Signed

B.A. Wilson for 2/3/87
K. W. Van Dyne, Resident Inspector Date Signed

B.A. Wilson for 2/3/87
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Approved by: B.A. Wilson 2/3/87
B. A. Wilson, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, unannounced inspection entailed direct inspection at the site, including backshift inspection, in the areas of surveillance testing, maintenance observations and reviews, operational safety reviews, plant operations, engineered safety features walkdowns, plant events, and followup on previous inspection items.

Results: Of the areas inspected, no violations or deviations were identified.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

C. M. Wethy, Vice President - Turkey Point
*C. J. Baker, Plant Manager-Nuclear - Turkey Point
F. H. Southworth, Senior Technical Advisor
E. Preast, Site Engineering Manager (SEM)
D. D. Grandage, Operations Superintendent
T. A. Finn, Operations Supervisor
J. Webb, Operations - Maintenance Coordinator
*J. W. Kappes, Maintenance Superintendent - Nuclear
R. A. Longtemps, Mechanical Maintenance Department Supervisor
D. Tomasewski, Instrument and Control (IC) Department Supervisor
J. C. Strong, Electrical Department Supervisor
*W. Bladow, Quality Assurance (QA) Superintendent
M. J. Crisler, Quality Control (QC) Supervisor
*J. A. Labarraque, Technical Department Supervisor
R. G. Mende, Reactor Engineering Supervisor
*J. Arias, Regulation and Compliance Supervisor
*R. Hart, Regulation and Compliance Engineer
W. C. Miller, Training Supervisor
P. W. Hughes, Health Physics Supervisor
G. Solomon, Regulation and Compliance Engineer
*J. Donis, Engineering Department Supervisor
J. J. Zudans, Nuclear Engineering, Human Factors Performance
*R. Broadnax, Training Support Supervisor

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

*Attended exit interview.

2. Exit Interview

The inspection scope and findings were summarized during management interviews held throughout the reporting period with the Plant Manager-Nuclear and selected members of his staff. An exit meeting was conducted on January 14, 1987. The areas requiring management attention were reviewed.

3. Open Item and Unresolved Item Followup (92701)

A review was conducted of the items listed below to assure that appropriate followup actions had been implemented on matters of concern to the inspectors.

(Closed) Inspector Followup Item (IFI) 250/84-34-05 and 251/84-35-05, AFW system walkdown discrepancies. The eight discrepancies listed in paragraph 8 of Inspection report 250/84-34 and 251/84-35 have been corrected. Drawing 5610-T-E-4062 sheet 3 of 5 has been revised and accurately depicts the AFW system and is satisfactory.

(Closed) IFI 250,251/85-13-10, Reinspect cleanliness of the Unit 3 and Unit 4 Residual Heat Removal (RHR) System areas. The RHR pump and heat exchanger rooms were inspected in December 1986 as documented in Inspection Report 250,251/86-45. During that inspection it was determined that the discrepancies noted in Inspection Report 250,251/85-13 had been corrected. Specifically, the mechanical snubbers were not missing cotter pins, the instrument air lines to valve 4-758 were not damaged, no wooden wedges were in use as pipe supports and the heat exchanger supports did not have any loose bolts. The RHR pump room sumps had been cleaned of original debris. However, some debris remained in the sumps and this fact was brought to the attention of licensee management. The Inspectors determined that the sump debris did not appear to pose a threat to the sump level control floats. The sump level system was operating satisfactorily. Consequently, the improved cleanliness and material condition of both the sumps and the pump and heat exchanger rooms merits the closure of this item.

(Closed) IFI 250/84-35-06 and 251/84-36-06, Control Room Operator unable to easily and accurately follow the performance of Operating Procedure (OP) 1004.2, Reactor Protection System Relay Testing. The procedure has been superseded by procedures 3/4-OSP-0491, and was revised to include a matrix attachment which clearly specifies which alarm targets will be received during each step of the reactor protection system test. The procedure is implemented by two reactor operators in the control room. One operator observes and verifies correct annunciator response and the other verifies the receipt of the correct status lights on the reactor protection panels. The Inspectors observed the use of the revised procedure during a Unit 4 reactor protection system test in December 1986. Discussions with several reactor operators verified that the procedure could be easily implemented and posed none of the human factors difficulties mentioned in Inspection Report 250/84-35 and 251/84-36.

(Closed) Unresolved Item (URI) 250,251/85-37-02, Use of the Nuclear Watch Engineer (NWE) as Fire Brigade Team Leader. This item resulted from a concern that the NWE could be the only Senior Reactor Operator (SRO) in the control room during a fire. Although two SROs were assigned to each shift, one, the Plant Supervisor - Nuclear, would leave the control room for as much as an hour to tour the plant. During these tours the NWE remained the sole SRO in the control room. Since the NWE is typically assigned as the Fire Brigade Team Leader, he could have dual responsibilities when alone in the control room during a plant fire. During a fire, the NWE as Fire Brigade Team Leader is required to report to the scene of the fire and direct fire fighting activities. However, as the only SRO in the control

room, he is also required to supervise the reactor operators as they control the nuclear units. One SRO is required by federal regulations to be in the control room at all times. The licensee had not promulgated instructions to the NWEs specifying desired actions to be taken under this circumstance. The licensee now places three SROs on each operating shift. Additionally, the NWE is procedurally prohibited, as specified in paragraph 4.4 of Administrative Procedure (AP) 0103.2, revision dated December 2, 1986, from being left as the sole SRO in the control room when assigned as Fire Brigade Team Leader. Consequently, the scenario of concern can no longer occur.

(Closed) URI 250, 251/85-26-05, Evaluate the testing of AFW valves using nitrogen. This URI involved a concern that the licensee was not evaluating the operation of the AFW system flow control valves during a simulated loss of instrument air. Upon loss of instrument air, a bottled nitrogen system automatically supplies pressurized nitrogen to position the flow control valves. The effectiveness of this nitrogen system was satisfactorily tested in November 1985 as per Temporary Operating Procedure (TOP) 279 for Unit 3 and TOP 278 for Unit 4. These procedures require that the AFW system be operated while instrument air is isolated. The bottled nitrogen system is then used to operate the flow control valves. The licensee plans to perform TOPs 278 and 279 on an 18 month periodicity. Permanent procedures are being developed and will replace the temporary procedures. However, the permanent procedure will provide for comparable nitrogen surveillance testing. TOPs 278 and 279 were reviewed by the inspectors and found to adequately test the nitrogen system under actual system operating conditions. The development and implementation of TOP 278 and TOP 279 has resolved the testing concerns discussed in Inspection Report 250,251/85-26.

4. Followup on Items of Noncompliance (92702)

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 that the responses were timely and that corrective actions were implemented within the time periods specified in the reply.

(Closed) Violation 250/84-35-02 and 251/84-36-02, Failure to test the Auxiliary Feedwater (AFW) system in accordance with the requirements of TS 4.10.4. This violation occurred because the licensee's surveillance test procedure, OP 7304.1, Auxiliary Feedwater System Periodic Test, did not require visual observation of each AFW flow control valve to verify that it received and responded to automatic valve positioning signals. Additionally, the licensee did not perform a post test lineup on the AFW flow control valves following the completion of surveillance testing. The licensee proposed corrective action in letter L-85-48 dated January 28, 1985. A review of the corrective action performed as a result of this violation was documented in Inspection Report 250,251/86-05. The violation

was not closed in report 250,251/86-05 because corrective actions had not been fully implemented. However, the licensee's corrective actions have again been reviewed and are considered complete and adequate. OP 7304.1 has been superseded by surveillance procedures 3/4-OSP-075.1 and 3/4-OSP-075.2. These procedures require, in Sections 7.1 and 7.2, that the flow control valves for the AFW train not being tested be verified to have opened in response to the AFW start signal. Subsequent to the completion of the surveillance tests the procedures require, in Attachment 3, that the valves be observed to have fully closed in response to the removal of the AFW start signal. The final valve positions are independently verified to be correct by a second person. The concern raised in Inspection Report 250,251/86-05 has also been adequately addressed. The current surveillance procedures specify that steam supply valve 1404 shall be used to test the A AFW pump on train 1 and steam supply valve 1405 shall be used to test the C AFW pump on train 1. This allows the visual observation of the response of the train 2 flow control valves to the independent initiating signals associated with valves 1404 and 1405.

(Closed) Violation 250,251/85-02-02, Failure to meet the requirements of TS 4.10.4 during AFW surveillance testing. This violation was issued because the licensee did not periodically test the installed nitrogen system which is used as a backup to the non-safety-related instrument air system in operating the AFW flow control valves. The licensee documented proposed corrective actions in letter L-85-130, dated April 1, 1985. The corrective actions have been completed and have been reviewed by the Inspectors and are considered satisfactory. Permanent plant procedures 3/4-OSP-075.3 for Units 3 and 4 have been developed and are implemented quarterly. The procedures verify that the installed AFW system nitrogen bottles can supply nitrogen to the AFW flow control valves. Additionally the procedures measure the rate of nitrogen consumption and verify that it is within acceptance limits. The nitrogen low pressure alarms are also verified to be properly functioning. These evaluations verify that the nitrogen system remains capable of controlling AFW flow control valve position upon loss of the instrument air headers. Additionally, the nitrogen system valve alignment is periodically verified to be correct in accordance with the requirements of Administrative Procedure (AP) 0103.19, Monthly Verification of Safety Related System Flowpaths.

(Closed) Violation 251/84-35-04, Failure to have adequate drawings showing the interface between the Unit 4 AFW system and the Nitrogen capping system. This violation resulted because plant drawings did not reflect the existence of three valves connecting the AFW system to the nitrogen capping system. Plant operating drawings 5610-T-E-4062, Sheet 3 and 5610-T-E-4061, Sheet 2 have been updated to properly reflect the Unit 4 nitrogen capping system interface with the Unit 4 AFW system. The interface valves have been tagged closed under the clearance control program to preclude the inadvertent operation of the valves. The licensee no longer uses the nitrogen capping system. The system will remain under administrative control until it is disconnected and removed from the plant.

5. Onsite Followup of Written Reports Of Nonroutine Events (97200)

The Licensee Event Report (LER) discussed below was reviewed and closed. 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 that the licensee had reviewed the 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.

(Closed) LER 250/85-014, Technical Specification (TS) - Refueling Cavity Level. On May 20, 1985, during Unit 3 refueling activities, the limits of TS 3.4.1.g (since amended to TS 3.10.7.2 a) were exceeded. The chain on the Unit 3 fuel transfer carriage drive motor broke and to facilitate repair activities it was necessary to lower the level of the fuel transfer canal. Due to an inoperable valve (3-798B) the normal drainage path to the Refueling Water Storage Tank was unavailable. The level was lowered by simultaneously draining the spent fuel pool, fuel transfer canal and refueling cavity to the Refueling Water Storage Tank via the B Residual Heat Removal pump. The A Residual Heat Removal pump was out of service for mechanical repairs. The level was lowered from 57 ft. to 53 ft. The 53 ft. level was approximately 21 ft. above the reactor vessel flange.

TS 4.3.1.g stated that with less than two Residual Heat Removal loops operable, the water level must be maintained at least 23 feet above the reactor vessel flange. If a Residual Heat Removal pump becomes inoperable with the water level was less than 23 feet then level was required to be immediately restored.

Upon realization that a TS action statement had been inadvertently entered, the licensee immediately returned the level to TS limits. The licensee held discussions with each Plant Supervisor - Nuclear (PSN) to emphasize the importance of being cognizant of TS requirements applicable to refueling operations. FPL inter-office correspondence PTN-OPS-85-136 was written by the Operations Supervisor and distributed to each PSN to further emphasize this concern. This LER and previous LERs resulting from apparent weaknesses in operator knowledge of TS requirements were documented in NRC inspection report 250,251/85-20 and followup is being tracked under URI 250,251/85-20-04.

The corrective actions specified in LER 250/85-014 are complete and appear adequate. No refueling water level violations were identified during the Unit 4 refueling outage of February 1986. Followup review relative to the concerns of URI 250,251/85-20-04 is not yet complete. Consequently, the URI remains open and the LER is closed.

6. NUREG-0737 Followup Inspection

(Closed) Item II.K.3.1.B - Automatic Power Operated Relief Valve (PORV) Isolation. This item required the licensee to assess the need for an automatic PORV isolation system. In response to this item FPL proposed that no modification to the existing system was warranted. This position was based on the results of Westinghouse Owner's Group report WCAP-9804, Probabilistic Analysis and Operational Data in Response to NUREG-0737, Item II.K.3.2, for Westinghouse NSSS Plants. WCAP-9804 concluded that "the concept of an automatic PORV block valve closure system, which closes the PORV isolation valves when lower pressure is sensed subsequent to a PORV failing to close, cannot be warranted on the basis of providing additional protection against a PORV LOCA." The NRC completed a review of this response and issued a Safety Evaluation based on a Technical Evaluation Report provided under contract by the Franklin Research Center. Based on the evaluations, the NRC concluded that an automatic PORV isolation system is not required for the Turkey Point Plant, Units 3 and 4 (NRC letter, Varga to Uhrig dated September 16, 1983).

7. Performance Enhancement Program (PEP) Summary

On December 17, 1986, the licensee announced several personnel changes affecting departments involved in implementing the PEP. These changes are summarized below.

Effective February 1, 1987, J. W. Kappes replaces R. J. Acosta as PEP manager.

Effective February 1, 1987, R. J. Acosta replaces G. J. Boissy as corporate QA director.

Effective April 1, 1987, G. J. Boissy will be assigned as Plant Manager - Nuclear of the St. Lucie Plant.

Effective January 1, 1987, D. A. Chaney replaced E. Preast as Site Engineering Manager.

Effective February 1, 1987, F. H. Southworth replaces J. W. Kappes as Maintenance Superintendent.

In January 1987, members of the Training Department began to move into the new Training Facility. The building is essentially complete. The vendor is currently performing simulator testing in Canada. Upon completion, the simulator will be shipped to Turkey Point and installed in the Training Facility. Simulator operation is scheduled for November 1987.

8. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations or deviations. No unresolved items were identified during this inspection period.

9. Monthly and Annual Surveillance Observation (61726)

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

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

AFW Nitrogen Backup System Low Pressure Alarm Setpoint and Leakrate Verification, 3-OSP-075.3 and 4-OSP-075.3

Intermediate Range Nuclear Instrument Analog Channel Operational Test, 4-OSP-059.2

Reactor Protection System Logic Test, 4-OSP-049.1

Auxiliary Feedwater System Flowpath Verification, 3-OSP-075.5 and 4-OSP-075.5

Power Range Nuclear Instrumentation Shift Checks and Daily Calibrations, 3-OSP-059.5

Auxiliary Feedwater Train 1 Operability Verification, 3/4-OSP-075.1 and 3/4-OSP-075.2

Within this area no violations or deviations were identified.

10. Maintenance Observations (62703)

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

The following items were considered during this review, as appropriate: that LCOs were met while components or systems were removed from service; that approvals were obtained prior to initiating work; that activities were accomplished using approved procedures and were inspected as applicable; that procedures used were adequate to control the activity; that trouble-shooting activities were controlled and repair records accurately reflected the maintenance performed; that functional testing and/or calibrations were performed prior to returning components or systems to service; that QC

records were maintained; that activities were accomplished by qualified personnel; that parts and materials used were properly certified; that radiological controls were properly implemented; that QC hold points were established and observed where required; that fire prevention controls were implemented; that outside contractor force activities were controlled in accordance with the approved QA program; and that housekeeping was actively pursued.

The following maintenance activities were observed and/or reviewed:

Nuclear instrument repair, Units 3 and 4

Inspection of the Unit 3 and 4 feedwater headers for pipe wall thinning

Repair of Unit 3 turbine generator control oil system

Repair of 4A feedwater control valve positioner linkage

Repair of the Unit 3 automatic rod control circuit

Troubleshooting C AFW pump electronic overspeed

Repair of the Power Operated Relief Valve 3-456

Troubleshooting of Power Range N-42 protection circuitry

Within this area no violations or deviations were identified.

11. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs, conducted discussions with control room operators, observed shift turnovers and confirmed operability of instrumentation. The inspectors verified the operability of selected emergency systems, verified that maintenance work orders had been submitted as required and that 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. Plant housekeeping/cleanliness conditions and implementation of radiological controls were 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 following safety related systems to verify operability and proper valve/switch alignment:

Unit 3 and Unit 4 High Head Safety Injection System
Unit 3 and Unit 4 Component Cooling Water Systems
Unit 3 and Unit 4 Intake Cooling and Discharge Canal Areas
Unit 3 and Unit 4 Electrical Switchgear Rooms
Emergency Diesel Generators
Auxiliary Feedwater System
Control Room Vertical Panels and Safeguards Racks

Within this area no violations or deviations were identified.

12. Engineered Safety Features Walkdown (71710)

The inspectors verified operability of the Unit 3 and Unit 4 High Head Safety Injection System (HHSI) by performing a complete walkdown of all accessible equipment. Portions of the systems are common to both Units. However, each Unit has independent supply paths to their respective cores. The following criteria were used, as appropriate, during the walkdown:

a. System lineup procedures matched plant drawings and the as-built configuration.

b. Equipment conditions were satisfactory and items that might degrade performance were identified and evaluated (hangers and supports were operable, housekeeping was adequate, etc.).

c. Instrumentation was properly valved in and functioning and that calibration dates were not exceeded.

d. Valves were in proper position, breaker alignment was correct, power was available, and valves were locked/lockwired as required.

e. Local and remote position indication was compared and remote instrumentation was functional.

f. Breakers and instrumentation cabinets were inspected to verify that they were free of damage and interference.

No discrepancies were identified in the HHSI systems. The systems were determined to be operable and capable of performing their design functions.

A partial walkdown of portions of the AFW system was performed on January 7, 1987. The inspectors identified areas were valve control could be improved. Each of the following items were discussed with the AFW system engineer, who began a review of the issues, and the Site Vice President.

a. Unit 3 valve 3-10-080 and Unit 4 valve 4-10-080, 250 psi auxiliary steam isolation valves, are not locked closed. The valves are not used and are required to be closed by procedures 3/4-OP-075. Opening either valve causes the AFW system to start. Starting the system by this manual method is not procedurally permitted and could render the system unreliable for automatic starting by changing governor oil pressure. Additionally, the pumps would be running while the flow control valves remained shut, resulting in a high back pressure and a potential for overheating the lubricating oil cooling system after approximately 15 minutes of operation. Such an event would be readily detectable by the plant staff and corrective action could be implemented. The administrative controls in place for valves on the locked valve list would greatly reduce the potential for inadvertent operation of the valves and thereby provide increased AFW system reliability. The licensee is adding these valves to the locked valve list.

b. Prior to recent system modifications, both the Unit 3 and Unit 4 AFW steam supply systems had pressure switches that opened control valves on low header pressure to allow minor leakage to vent to atmosphere. Subsequent to concerns raised during AFW system inspections in the Fall of 1985, the licensee determined that the vent system was not required to assure AFW system operability. Two pressure switches existed for each Unit, one for each steam train. Each pressure switch was capable of being isolated by two root valves. The pressure switches and control valves for each Unit have been removed and the pipes capped. The Unit 4 valves are required, by procedure 4-OP-075, to be closed and the valves were verified by the Inspectors to be closed. Procedure 3-OP-075 specifies that the Unit 3 root valves be open and visual inspection revealed that the valves were actually open. However, this requirement is undesirable because, on AFW system initiation, it places full steam generator pressure on the threaded pipe cap which was installed when the pressure switch was removed. Closing the Unit 3 valves would provide pressure isolation for the caps and would provide consistent valve alignment between Units 3 and 4. Additionally, drawing 5610-T-E-4061, Revision 18, which applies to both Units 3 and 4, shows that the desired valve position is closed. Consequently, the valve position requirements of Unit 3 procedure 3-OP-075 conflict with the valve position requirements of the drawing. This is not the case for Unit 4 procedure 4-OP-075. However, the Unit 4 root valves have not been retagged to show that their normal position is closed. The tags specify that the valves are normally open when actually, for Unit 4 only, they are normally closed.

c. Drain valve number SWLU 3-081 on the Unit 3 Secondary Wet Layup (SWLU) system is mounted very close to AFW steam header train 1. The AFW steam pipe lagging has been cut away to accommodate the SWLU drain line. Even so, the drain line is no more than 1/4 inch from the steam header. A concern exists that the pipes could bang together during a seismic event. Even though the drain line is small, an engineering review of the potential problem is appropriate. The AFW system engineer has begun a review of the pipe configuration.

d. The Unit 3 and 4 AFW steam supply piping has been modified to remove air operated flow control vent valves 2914 and 6448. Although drawing 5610-T-E-4062 has been updated to reflect this change, drawing 5610-T-E-4061, Sheet 3, Revision 26 has not been updated to show the deleted automatic vent valves.

Within this area no violations or deviations were identified.

13. 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. The licensee plans to issue LERs on each event within 30 days following the date of occurrence.

a. On December 27, 1986, the Unit 3 reactor was manually tripped due to complications resulting from a large turbine runback. The turbine runback resulted from a loss of governor system oil pressure, which was subsequently attributed to dirt and/or debris in the oil. The licensee believes that the dirty oil temporarily blocked small orifices, prevented normal oil flow and resulted in low oil pressure. The governor system reduced turbine load as per design on decreasing oil pressure. During the resulting transient, two significant systems failed to operate properly. The control rods failed to automatically step in as designed during the runback and Power Operated Relief Valve (PORV) 3-456 did not fully reseat after opening. Since automatic rod motion in the inward direction did not occur, reactor power remained above turbine power during the initial stages of the transient. This resulted in increasing primary and secondary temperatures and pressures and resulted in the actuation of both the steam generator safety relief valves and PORV 3-456. The other PORV did not open because it had previously been determined to be leaking and consequently, it's block valve was being kept shut. Manual rod control was promptly initiated but the manual system was not designed to immediately correct large turbine/reactor power mismatches. Manual rod control operated as designed.

Since reactor pressure was approaching the reactor trip setpoint and temperatures were increasing, a decision was made to manually initiate a Unit 3 reactor trip. This decision was entirely appropriate under the circumstances and preceded what would most certainly have been an automatic reactor trip on high pressurizer pressure.

Subsequent to the reactor trip, both primary pressure and temperature decreased as would be expected. However, since PORV 3-456 did not fully reseat, pressure decreased below the expected value of 2235 pounds per square inch (psi). The discrepancy was promptly identified by the control room operators and block valve 3-535 was shut to isolate the PORV leakage path. Primary temperatures and pressures returned to normal.

This transient was controlled well by the on-shift operations staff. The decision to manually trip the reactor was both timely and appropriate and was made in recognition of deteriorating plant parameters that would eventually result in reaching automatic trip setpoints. As a result, actuation of the pressurizer high pressure safety valves was avoided. The stuck open PORV condition was quickly identified and a low pressure transient was avoided by closing the block valve. As a result, the low pressure safety injection was not required.

The licensee will issue, by January 27, 1987, a LER describing this transient and specifying corrective actions. The turbine governor oil system was cleaned of debris and satisfactorily tested. A failed circuit card was repaired in the automatic rod control system. The system was returned to service following successful post maintenance testing. The PORV was repaired. Inspection of this valve revealed small scratches on the valve piston which could have been made as a result of foreign material being wedged between the piston and the valve seat. Since the exact reason the valve failed to reseat was not apparent, the licensee plans to send the valve parts to the manufacturer for additional analysis. Followup activities associated with this transient event will be followed under the LER.

b. On January 6, 1987, the Unit 4 reactor automatically tripped from 100 per cent power due to false Over Power Differential Temperature (OPDT) and Over Temperature Differential Temperature (OTDT) trip signals. The primary and secondary systems responded normally following the trip. Power Range Nuclear Instrument (PRNI) N-42 was out of service while its OPDT trip setpoint was being calibrated. Its OPDT and OTDT bistables (Loop B) were tripped as required by procedure. This resulted in one of two required trip channels sending a trip signal to the reactor protection system. This lineup is required whenever a PRNI is taken out of service. The reactor trip resulted when an additional channel (Loop C) of OPDT and OTDT protection briefly alarmed. No actual OPDT or OTDT condition existed.

Subsequent troubleshooting revealed some loose test jacks in the reactor protection racks which when wiggled resulted in spikes on the OPDT and OTDT protection circuits. The licensee determined that spikes resulting from vibration of the loose test connections provided the second of two trip inputs necessary to trip the reactor. The test connections were repaired and the OPDT and OTDT protection channels were tested and returned to service.