U.S. NUCLEAR REGULATORY COMMISION

REGION I

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Report No. 50-293/85-03

Docket No. 50-293

License No. DPR-35 Category: C

Licensee: Boston Edison Company
800 Boylston Street
Boston, Massachusetts 02199

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: February 1, - March 4, 1985

Inspectors: William J Raymond 3/26/85
for J. Johnson, Sr. Resident Inspector — Date

William J Raymond 3/26/85
for M. McBride, Resident Inspector — Date

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Approved by: William J Raymond 3/26/85
for L. Tripp, Chief, Reactor Projects Section 3A, DRP — Date

Inspection Summary: Inspection on February 1, - March 4, 1985 (Report No. 50-293/85-03)

Areas Inspected: Routine unannounced safety inspection of plant operations including: Followup on previous findings, operational safety verification and ESF walkdown, events, surveillance testing, maintenance and modifications, health physics activities, independent verification of operating activities (I.C.6) and, followup to NRC Information Notice No. 84-86. The inspection involved 179 inspection-hours by two resident and one region-based inspectors.

Results: Five violations were identified (failure to take prompt corrective action for QA surveillance findings, Paragraph 3.b; use of out of calibration test equipment, Paragraph 5.b; failure to perform surveillance testing on scram instrumentation, Paragraph 5.b; failure to perform surveillance testing on control rod block instrumentation, also in Paragraph 5.b; and failure to control documents, Paragraph 6.b.4). Concerns regarding establishment and implementation of a program for independent verification of operating activities are described in Paragraph 8.c.

DETAILS

1. Persons Contacted

   Within this report period, interviews and discussions were conducted with members of the licensee and contractor staff and management to obtain the necessary information pertinent to the subjects being inspected.

2. Followup on Previous Inspection Findings

   (Closed) Unresolved Item (84-15-01). Revise procedure 8.B.12, Fire Protection System Flow Test, Rev. 4 to include quantitative acceptance criteria of 1000 gpm at 20 psig. Revision 5 to this procedure was approved on December 15, 1984 and includes quantitative acceptance criteria of 1000 gpm at 20 psig. This item is closed.

   (Closed) Unresolved Item (84-39-02). Review licensee evaluation of the disagreement between the FSAR and station procedure No. 8.5.1.3 on the maximum core spray discharge valve closing time. The inspector reviewed 1981 correspondence between the QA group and station personnel on this item. The correspondence indicated that General Electric Co. has evaluated the longer closing time used in the procedure (12.5 sec. vs 10 sec. in the FSAR) and found it acceptable. QA personnel subsequently stated that the General Electric assessment was documented in Safety Evaluation No. 1408, dated March 19, 1982 and that the safety evaluation had been approved by the Nuclear Safety Review and Audit Committee at meeting No. 82-10. This item is closed.

   (Closed) Unresolved Item (84-39-04). Review MSIV closing times. The licensee's Nuclear Engineering Department and station Technical Group reviewed the inspector's concerns regarding a misapplication of a .5 second time and agreed that the surveillance test (limits of 3.5 to 5.5 sec.) was not in accordance with the Technical Specifications (limits of 3 to 5 sec.). The licensee stated that the technical acceptability of the test limits had previously been reviewed under Unresolved Item 79-04-02 and had been accepted in Inspection Report 50-293/79-21. The inspector acknowledged this, but maintained that surveillance test limits must meet the Technical Specifications and that prior to use of the 3.5 to 5.5 sec. limit again, the Technical Specifications must be revised via the change process. Revision 10 to Procedure No. 8.7.4.4, MSIV Trip, was approved on February 6, 1985 and requires all MSIVs to close within the time specified in TS Table 3.7.1 (3-5 seconds). This item is closed.

   (Open) Violation (84-39-01) Review licensee evaluation of core spray and residual heat removal systems with degraded pipe supports and hangers in 1984. The licensee evaluation of the operability of the core spray and residual heat removal systems during 1984 is documented in memo NED 85-146, dated February 19, 1985. This evaluation included a pipe stress analysis of both systems and concluded that both systems were operable in the degraded condition. The inspector had no further questions. This item is open pending review of the licensee's corrective actions regarding untimely issuance of Failure and Malfunction Reports.

(Closed) Follow Item (85-01-03). Review the basis for the licensee review of small bore piping. The inspector reviewed the basis for a small bore piping secondary stress evaluation which was conducted after plant startup in December, 1984. The piping was installed during the 1984 refueling outage. The inspector verified that the ASME code, Section XI, IWA 7000, W80 addenda does not require that this secondary stress be evaluated for this piping. The inspector reviewed the Project Quality Plan for the outage and noted that the licensee did require the evaluation, but did not require it to be completed prior to plant startup in December, 1984. The inspector had no further questions. This item is closed.

3. Operational Safety Verification and ESF Walkdown

a. Scope and Acceptance Criteria

The inspector observed control room operations, reviewed selected logs and records, and held discussions with control room operators. The inspector reviewed the operability of safety-related and radiation monitoring systems. The inspector verified the operability of the reactor building closed cooling water (RBCCW) system by performing a walkdown of accessible portions of the "A" loop of that system. The walkdown included a review of valve lineup procedures and plant drawings to ensure that they reflected the as-built configuration. Valves were verified to be in the appropriate position, have power available, and be locked as appropriate. Selected pipe supports and hangers were visually inspected for signs of degradation. General housekeeping was reviewed during the walkdown. Tours of the reactor building, turbine building, drywell, station yard, switchgear rooms, "A" residual heat removal (RHR) quadrant room, and the control room were conducted. Observations included a review of equipment condition, security, housekeeping, radiological controls, and equipment control (tagging).

These reviews were performed in order to verify conformance with the facility Technical Specifications and the licensee's procedures.

b. Findings

(1) During the period of February 1-7, 1985, the resident inspector and a region-based security specialist inspector reviewed the licensee's actions taken in response to issuing an incorrect badge in December, 1984. The problem was determined to be isolated, and the licensee's corrective actions were deemed appropriate. No inadequacies were identified.

(2) On February 4, 1985, the inspector held discussions with the licensee's fire protection officer regarding a potentially generic issue at another power plant involving Electro Thermal links failing to burn open as designed. The licensee representative acknowledged the inspectors comments and stated that the station had not had similar problems with fusible links. No deficiencies were identified.

(3) On February 6, 1985, the inspector reviewed the status of the Operations Quality Assurance Surveillance Program with a licensee representative. The purpose of this review was to determine whether the surveillance reviews were being performed and whether the licensee personnel were appropriately correcting any findings.

The inspector determined that, in general, the OQA surveillance program was being implemented and that the findings were significant and in several functional areas. However, it did not appear that the licensee managers were taking prompt corrective action to the findings. The monthly report of Deficiencies and Surveillance Findings as of February 1, 1985 described 29 surveillance findings that included overdue (or rejected) initial responses for up to 221 days and overdue corrective actions for up to 306 days.

Nuclear Operations Procedure NOP83A1, Nuclear Operations Surveillance Monitoring Report (dated September 30, 1984) requires 1) the cognizant Group Leader to return the original surveillance Finding Sheet to QA within five days, and 2) the Department Managers and Group Leaders to implement prompt corrective actions. Unacceptable responses are required to be reported to the Vice Presidents, Senior Vice President, and President if necessary for resolution. The inspector noted that periodic status reports were being provided to these managers, but this was apparently not effective in resolving the problems.

Examples of untimely corrective action are listed below:

Finding No.	Description	Initial Response	Corrective Action
84-1.2-5.1	Inadequate replacement of main steam test plugs		49 days overdue
84-1.2-2-1	Inadequate surveillance test (ECCS alarms and relays)	107 days overdue	
84-1.4-2-3	Unapproved standby liquid control tank heater setpoint		276 days overdue
84-3.2-4-1	Station procedure for safety evaluation process not in accordance with Nuclear Org. Procedure		245 days overdue
84-9.1-4-1	Temporary modification procedure did not include gage calibration	46 days overdue	
84-1.3-10.1	Tags left on breakers with closed MRs	57 days overdue	

84-1.1-14-1	Improper selection of battery pilot cells	149 days overdue	
84-1.1-17-2	Status of electrical jumpers not maintained	119 days overdue	
84-4.2-1-1	Inadequate Emerg. diesel gen. sprinkler test.		306 days overdue
84-1.4-3-1	Inadequate HPCI instrument gage cal.		215 days overdue
84-1.1-17-1	Uncontrolled electrical jumper tags hung in control room	119 days overdue	
84-4.1-3-1	Gas cylinders not secured in station		287 days overdue
84-9.1-2-1	Uncontrolled fire extinguishers	56 days overdue	
84-6.1-2-1	No verification of licensed operator education	221 days overdue	

Failure to implement prompt corrective action in response to Operations QA Surveillance Findings is a violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action (85-03-01).

(4) On February 12, 1985, while the reactor was shutdown, a licensed reactor operator indicated that the control room annex was considered part of the control room. The annex is separated from the control room by a block wall and security access equipment must be used to enter one area from the other. Licensee procedures do not explicitly state which areas are considered to be in the control room. In response to this incident, the licensee stated that a memo would be issued to licensed operators indicating which areas are part of the control room. The inspector had no further questions.

(5) The inspector observed portions of the shutdowns initiated on February 8 and 15 and the startups initiated on February 15 and 17. The inspector reviewed startup checklists (OPER1) and vessel heatup and cooldown rates (OPER7). No concerns were identified.

(6) On February 20, 1985, the following problems with the licensee's method of tracking out-of-service time for the rod block monitors were identified.

-- The portion of form OPER 38A used to track rod block monitor out-of-service time was incorrectly filled out. Because of the error, shift personnel believed that the "B" rod block monitor had been out of service for 4 hours during February instead of 11 hours.

-- The OPER 38A form tracked the out-of-service time for the monitors by calender months instead of by 30-day periods as required by the technical specifications.

-- The Nuclear Operating Supervisor (NOS) on duty incorrectly believed that the rod block monitor was operable when manually bypassed with the 905 panel joystick.

The licensee stated that the OPER 38A forms would be revised and personnel instructed in their use. The NOS was counseled on the correct status of the rod block monitors when manually bypassed. The personnel errors appeared to be isolated. The inspector had no further questions.

(7) On February 22, 1985, at about 8:00 am, the inspector noted a slight disagreement between three estimates of core thermal power from the process computer. The C077 estimate was 2,002 MW, which is greater than the steady state power limit of 1998 MW in the operating license. The C017 estimate was slightly less than 1998 MW. Repetitive OD-3 estimates ranged between 1,998 and 2,002 MW. All estimates are based on energy balances. C077 is an instantaneous value, C017 is a 10 minute averaged value, and OD-3 is an instantaneous value, but is the most accurate since it contains sensor error corrections.

The inspector reviewed records of core themal power prior to February 22, 1985, which indicated that the average reactor power over one-hour time periods did not exceed 1998 MW, consistent with the 1980 NRC guidance on the interpretation of licensed power level in the control room.

Accordingly, the inspector concluded that the observed occurrence of a computer power estimate temporarily above the licensed power was acceptable.

(8) The licensee informed the inspector that a minor flow instability exists in the "A" recirculation loop. General Electric has evaluated this instability, and believes it reflects a bistable vortex phenomena in the jet pump riser pipes. Periodically, the loop A drive flow takes a small step increase (about 1 percent). After a few minutes, the loop flow decreases to the original flow rate. Total core flow mimics the loop flow and APRM power increases slightly during the step increases. No limits were exceeded.

General Electric has indicated to the licensee that the phenomena is related to the design of the recently installed recirculation piping, is understood, does not constitute a safety issue, and does not impact on the plant. The licensee has asked General Electric to prepare a formal safety evaluation on the phenomena.

The acceptability of the observed flow instability is unresolved, pending review of the licensee safety evaluation (85-03-02).

(9) On February 20 and 21, 1985, portions of the "A" loop of the reactor building closed cooling water (RBCCW) system were walked down. The walkdown included tours of the auxiliary bay, reactor core isolation cooling (RCIC) quadrant, and "A" residual heat removal (RHR) quadrant.

The inspector noted that most of the RBCCW valves were locally labeled, which indicates that the licensee's recent program for valve labeling has been making effective progress. Minor problems concerning valve designation, a missing cap for a drain line, and the connection of a rubber hose to the system were identified and reported to the Chief Operating Engineer. These problems are described in Attachment I to this report.

During the walkdown, the inspector noted that a catch basin under a leaking RHR valve in the "A" RHR quadrant had no drain hose and was leaking contaminted water over pipes and onto the floor. The inspector was aware of previous licensee decontamination efforts in this area. Since the lack of a drain hose was leading to the area being contaminated again, the licensee was informed of the problem. The inspector had no further questions.

(10) On February 28, 1985 the inspector reviewed a licensee report (NED 84-965 dated December 14, 1984) which described maintenance and repair of cable coatings and marinite fire barriers. This report was provided to the inspector following previous questioning of the acceptability of broken pieces of marinite fire barriers between electrical cable trays throughout the reactor building. The report concludes that the as found conditions were acceptable because of the presence of an equivalent flamemastic cable coating. The inspector noted that this coating was in place and had no further questions at this time. No unacceptable conditions were identified.

4. Followup on Events and Nonroutine Reports

a. Events

(1) On February 1, 1985, the inspector followed up on the licensee's identification of two cases of improperly operating instrumentation. On January 22, 1985, one of four high drywell pressure switches (PS 1001-83A) did not trip during routine calibration (8.M.2-2.1.5).

The other three switches operated properly and within setpoint. The licensee's investigation revealed the problem to be due to a displaced hinge pin in the switch. It was reset, and the switch operated properly. The licensee stated that construction work in the area in November 1984 may have affected the switch operation, although post work testing at that time had demonstrated proper operation.

On January 29, 1985, during routine calibration, two of four main steam line low pressure instruments were out of tolerance (865 and 875 psig vs. a required > 880 psig). The inspector reviewed other calibration records and held discussions with the licensee's I&C supervisor. The licensee stated that in the past, some of these switches (Barksdale B2T-A12SS 50-1700 psi) had tended to relax during a lengthy shutdown condition. The inspector verified that these switches had been calibrated at the end of a lengthy outage and just prior to startup in November, 1984. The licensee's corrective actions included readjusting the two switches to within tolerance and increasing the surveillance frequency to monthly (from once-per-three months) to assure proper operation. No inadequacies were identified. The inspector determined that the licensee's actions were appropriate.

(2) On January 31, 1985, the licensee reported to the NRC operations center local news media interest in a release of particulate radioactive material from the main stack onto personnel and the ground directly below the stack on licensee's property.

The inspector reviewed the details of this event including records of surveys, reports, operating logs, and recorder traces, and held discussions with licensee personnel in the operations and radiological groups.

The release of particulate radioactive material (pieces of painted metal) took place at 9:30 am on January 31, 1985 and lasted for about five minutes. Two personnel were slightly contaminated by discharged moisture and metal flakes and were subsequently decontaminated on site. No internal deposition was identified. The material released from the stack fell down to the ground on the licensee's fenced-in restricted area surrounding the main stack building. Licensee's surveys as well as an independent (Yankee Atomic Electric Company Environmental Laboratory) survey did not indicate further residual material or release of material off site.

By analyzing the material collected the licensee estimated that about 0.78 microcuries of Cesium-137 and 0.65 microcuries of Cobalt-60 were present. The inspector compared this amount and the duration of the evolution with the release rate limits in Technical Specification Section 3.8.B.2. The release (there is no indication of actual release from licensee property) was less than the T.S. limit by a factor of about one thousand.

The licensee inspected the off gas filters in the main stack building, and other equipment in the augmented off gas building. Other than a deteriorated outlet retainer on the on-line off gas filter, no further damage was noted. Although the licensee initially suspected that operation of a condensate deminerlizer caused a high flow of air into the feedwater and out the off gas system, that cause has been ruled out. Based on the moisture observed by the workers, the licensee currently suspects that a buildup of moisture on the off gas filter caused a pressure buildup, which when relieved, resulted in a quick release of air that shook loose the paint and metal flakes.

The inspector had no further questions at this time. No inadequacies in the licensee's actions were identified.

(3) On February 1, 1985 the licensee notified the NRC operations center that a controlled shutdown was in progress because of having two Main Steam Isolation Valves (MSIVs) out of tolerance for closing time (5.9 and 8.2 seconds vs. a maximum specified of 5 seconds). The testing had been done on all eight valves in response to an unresolved item regarding acceptable times (see UNR 85-39-04 in Paragraph 2, above).

The inspector discussed this event with the on-duty Watch Engineer. The licensee's actions included 1) readjusting the outboard "D" valve time to a satisfactory value (4.6 seconds) via the normal dash pot adjusting needle valve, and 2) isolating the "B" steam line with the outboard valve until a drywell entry could be made to work on the "B inboard MSIV. The inspector verified that the "B" steam line was isolated.

On February 8, 1985, the drywell was deinerted to inspect the "B" inboard MSIV. A reactor shutdown was initiated later on February 8 to satisfy technical specification requirements for operating the reactor with the drywell deinerted.

After consulting with General Electric Co. the licensee measured the time from red light to green light indication (in addition to the normal timing from switch closure to green light indication). These test results indicated that the air operating system was sluggish. Following replacement of parts in the air operating mechanism on the "B" inboard and "D" outboard valves, the licensee re-timed all valves with satisfactory results. The licensee stated that the valves were tested several times with consistent results.

The inspector had no further questions. No inadequacies were identified.

(4) On February 6, and again on February 26, 1985, the licensee's security computer system was inoperable. The inspector verified that required compensatory actions were taken until the system was returned to normal. The licensee's actions were deemed appropriate. No inadequacies were identified.

(5) During the power reduction on February 9, the "A" recirculation motor generator (MG) set tripped on high generator differential overcurrent and could not be restarted. The reactor was subsequently shut down on February 9 and 10 to repair the "A" recirculation pump motor and to repair the MSIVs, as described in (3) above.

The reactor was placed in cold shutdown at 1:56 am on February 11, 1985.

No additional concerns were identified.

(6) During the course of reactor startup on February 15, 1985, at 10:50 am, licensee inspection detected a leak in the drywell in a two-inch reactor vessel bottom drain line. The leak was due to a through-wall defect in a weld on the down stream side of a manual block valve (HO-65) in the drain line. The drain line is part of the primary coolant boundary and is used to direct water from the bottom of the reactor vessel to the reactor water cleanup system during power operation. The block valve is normally open and was the only valve in the drain line between the leak and the reactor vessel.

A reactor shutdown was promptly initiated and all control rods were inserted by 2:54 pm on February 15, 1985. The licensee notified the NRC via the ENS telephone line of the shutdown at 12:15 pm on February 15, 1985. The licensee completed repairs on the drain line weld and hydrostatically tested the line on February 17, 1985. A reactor startup was initiated at 5:08 pm and the reactor was critical at 7:06 pm on February 17, 1985.

The inspector visually inspected the valve inside the drywell on February 16, reviewed the maintenance request for the repairs (MR 85-106), and reviewed the documentation for the hydrostatic test.

Concerns about the completeness and accuracy of licensee documentation of hydrostatic tests are discussed in section 5.b.6 of this report. The inspector had no further questions.

(7) On February 21, 1985, the licensee reported via the ENS telephone line that the following surveillance tests had been missed during the reactor startup in December 1984 through January 1985:

-- Main turbine stop valve closure functional test, Procedure No. 8.M.1-26,

-- Rod block monitor functional test, Procedure No. 8.M.2-3.1, and

-- Rod block monitor calibration, Procedure No. 8.M.2-3.2.

Reactor power was reduced to 70% at 9:00 pm on February 21, 1985 to enable the stop valve functional test to be conducted. The rod block monitor calibration had been conducted previously, on February 19, 1985. The missed surveillances are discussed further in Section 5.b.3 of this report.

(8) On February 26, 1985, at 2:12 pm, a half scram occurred on reactor protection system (RPS) channel "A", but no initiating cause could be identified. The licensee notified the NRC via the ENS telephone line of the event at 2:39 pm on February 26. The RPS logic and alarms were promptly tested and found to be functioning normally. The licensee believes that the half scram signal may have been generated by a worker bumping an RPS instrument rack in the reactor building.

No inadequacies were identified.

(9) On February 26, 1985 at 11:29 pm the plant experienced an unplanned feedwater system transient due to erratic operation of the "A" feedwater regulating valve. Investigation revealed a faulty proportional amplifier in the valve control circuit. This was replaced and all systems returned to normal operation by 4:45 am on February 27, 1985. No safety concerns or other inadequacies were identified.

b. Review of Licensee Event Reports (LER's)

Licensee Event Reports submitted to the NRC:Region I office were reviewed to verify that the details were clearly reported and that corrective actions were adequate. The inspector also determined whether generic implications were involved and if on site followup was warranted. The following reports were reviewed:

No.	Subject
85-01	Standby Liquid Control System Inoperable
84-06 Rev. 1	Fire Door Degradation

The events surrounding LER 85-01 and NRC followup are described in Inspection Report No. 85-01. LER 84-06, Rev. 1, describes the results of an engineering analysis which concluded that the previously questionable fire doors had been functional and describes the planned return of these doors to an Underwriters Laboratory listed condition prior to the next refueling outage. The inspector had no further questions. No unacceptable conditions were identified.

5. Surveillance Testing

a. Scope

The inspector reviewed the licensee's actions associated with surveillance testing in order to verify that the testing was performed in accordance with approved station procedures and the facility Technical Specifications.

A list of items reviewed is included at the end of this report in Attachmemt 1.

b. Findings

(1) Problems regarding independent verification of return to service following testing are described in Paragraph 8, below.

(2) On February 19 the inspector observed portions of a calibration of both rod block monitors. The calibration was being done to verify the accurracy of the monitors after unanticipated rod blocks were received during the startup sequence on February 18 and 19.

The following problems were identified:

-- The terminology on the data sheet for the calibration Procedure, No. 8.M.2-3.2, did not match the terminology in the procedure. This confused the technician performing the calibration and he had to make clarifying notes on the data sheets to ensure the proper adjustments were made to the monitors. The Chief Maintenance Engineer subsequently stated that the procedure was modified to clarify the data sheets.

-- The inspector asked the licensee to evaluate the adequacy of the rod block clamp (i.e., fixed limit) calibration in Procedure No. 8.M.2-3.2. This clamp should occur at 107% reactor power and be independent of recirculation flow. The procedure only ensures that a rod block is received at 107% and does not verify that the rod block is generated by the clamp rather than by a flow biased circuit. If the block were generated by a flow biased circuit, the block would increase with increased recirculation flow and the block could be "set up" to still higher levels by the rod block monitor control switches. The licensee agreed to change the procedure to ensure that the clamp action is verified.

-- Digital multimeter No. I-860C, six days past due for calibration, was used to calibrate the rod block monitors. Also, during a review of calibrated test equipment available for use, the inspector found that frequency counter No. 134, was two months past due for calibration and decade box No. IDC 6A was one month past due for calibration. The licensee promptly removed both instruments from the locker and recalibrated the rod block monitors using a different multimeter.

Failure to establish measures to assure that measuring and testing devices used in activities affecting quality are properly controlled is a violation of Criterion XII of 10 CFR 50 Appendix B (85-03-03).

The licensee stated that a preventive maintenance computer listing identifies instruments that are nearing the end of their calibration periods so that the instruments can be removed from service two weeks prior to calibration expiration. However, this system is not required by licensee procedures and I&C supervisors indicated that instruments were not removed from service recently because of a work backlog. Instead, the individual technicians were relied on to check instrument calibration due dates prior to use. The technicians were not required to record the calibration due dates for the test equipment on surveillance records.

The inspector noted that the I&C instrument issue area had an instrument sign out log that had not been used in over a month. This log was also not required to be used by procedure, although the licensee indicated that the technicians were supposed to record each instrument that was removed from the instrument locker on the log.

At the exit meeting, the licensee stated that maintenance and I&C test equipment had been reviewed to ensure that the equipment was not overdue for calibration. No additional problems were identified during the review. The licensee further stated that until the problem was evaluated, an individual would be assigned responsibility for issuing all the I&C test equipment.

(3) On February 21, 1985, the licensee notified the NRC via the ENS telephone line that the following three surveillances had been missed during the startup sequence in December, 1984 and January, 1985:

-- Procedure No. 8.M.1-26, "Turbine Stop Valve Closure (turbine first stage pressure greater than 305 psig)." This surveillance functionally checks the stop valve closure logic and alarm circuits and duplicates portions of surveillance No. 8.M.1-11 (see below). Surveillance 8.M.1-26 is normally scheduled every six months. It was later determined that this test is not used to satisfy technical specification requirements.

-- Procedure No. 8.M.2-3.1, "Rod Block Monitor". This surveillance is scheduled monthly and is used to satisfy the monthly instrument functional test requirement in Technical Specification Table 4.2.C. The test was last done on December 14, 1983.

-- Procedure No. 8.M.2-3.2, "Rod Block Monitor Calibration". This surveillance is scheduled every six months and is used to fulfill the once-per-six-month rod block monitor calibration requirement in Technical Specification Table 4.2.C. This test was last done on November 17, 1983 and was not repeated until February 19, 1985. This missed surveillance is not considered licensee identified because the problem was found when the inspector asked to see the test results, and the licensee could not find any record of the test.

The licensee stated that the three tests were missed because specific due dates had not been entered for the tests in the Master Surveillance Tracking Program (MSTP). The MSTP is a computerized data base which is used to schedule surveillances. The MSTP schedules typically include dates when surveillances will be overdue by 25% of the surveillance period. Several days before the 25% date, a pink priority notice is sent to the licensee group that is responsible for the surveillance.

The three missing surveillances were required by the MSTP schedule to be completed by "startup." No pink priority notices were generated because no specific due dates were assigned for the completion of the surveillances. The MSTP schedules included the dates when the surveillances were last done and the required frequencies for the tests. However, the licensee group responsible for the surveillances, I&C, indicated that they had focused on MSTP due dates and not the other information (e.g., required frequencies) on the MSTP schedule. They further stated that tests with pink priority notices were given priority over the missed surveillances, delaying the latter.

During followup to this event, the inspector identified the following examples of a violation of the requirements of Technical Specification 1.0.V and Table 4.2.C (85-03-04).

-- Failure to functionally test the upscale and downscale trips for the rod block monitor prior to declaring the monitors operable on January 10, 1985. This problem was caused by the delay in conducting test No. 8.M.2-3.1, discussed above. While the licensee identified this example, additional examples below were not identified. Therefore, licensee identification and corrective actions were inadequate and this example has been cited.

-- Failure to calibrate the rod block monitors prior to declaring the monitors operable on January 10, 1985. This problem was caused by the delay in conducting test No. 8.M.2-3.2, discussed above.

-- Failure to functionally check the portion of the rod block logic system which is operable in the run mode prior to declaring the logic system operable, on December 29, 1984 and January 9, 1985. This problem was caused by delays in conducting tests 8.M.2-3.6.1 and 8.M.2-3.6.2. These tests were also listed on MSTP schedule with startup due dates. The I&C group, which was responsible for the tests, initially indicated that other surveillance tests were done which duplicated the logic checks. However, the inspector could find no evidence that these other tests had been completed in a manner which satisfied the technical specification frequency requirements.

-- Failure to functionally test the downscale rod block trips for the average power range monitors (APRM) prior to declaring the monitors operable in the run mode on December 29, 1984 and January 9, 1985. This functional test is a part of test No. 8.M.1-3. Licensee procedures are inadequate in that they do not require test 8.M.1-3 to be completed until the reactor is between 30% and 60% power. Power had not gone above 60% before January 13, 1985, when the test was completed.

(4) During further followup to the above surveillance problems, the inspector identified the following examples of a violation of the requirements of Technical Specification 1.0.V and Table 4.1.1 (85-03-05).

-- Failure to functionally test the APRM high flux scram trips as soon as practicable after the monitors were declared operable in the run mode on December 29, 1984. In addition, the licensee failed to functionally test the APRM downscale scram trips prior to monitors being declared operable in the run mode on December 29, 1984 and January 9, 1985. These trips were not tested because test No. 8.M.1-3 was delayed until January 13, 1985 as discussed above. An APRM functional test for modes other than run, No. 8.M.1-3.1, was completed on January 4 and 12, 1985. This test checks the high flux scram trips, but not the downscale scram or rod block trip.

-- Failure to functionally test the APRM inoperative scram trips prior to the monitors being declared operable in the startup mode on December 24, 1984 and prior to the monitors being declared operable in the run mode on January 9, 1985. The licensee initially indicated that Procedure No. 8.M.1-3.1 functionally tested this trip when the reactor was in the startup mode between December 24 and 29, 1984. However, test No. 8.M.1-3.1 did not functionally test the inoperative trips.

The inoperative trips were not functionally tested while the reactor was in run mode until test No. 8.M.1-3 was completed on January 13, 1985.

(5) During the review of the APRM functional tests, the inspector noted that other existing licensee surveillance tests could satisfy the technical specification requirements if checks of local panel alarm lights in these test procedures demonstrate operability of the APRM output relays. The licensee initially indicated that the alarm lights did show that the relays had tripped but the licensee could not demonstrate this on schematic drawings. Subsequently, the licensee stated that the I&C surveillances would be reviewed and their technical basis determined. This item will be examined during a future inspection (Open Item 85-03-06).

(6) On February 17, 1985, a ASME Class I hydrostatic test was performed on a section of the reactor vessel drain line following weld repairs to valve HO-65. A through wall defect had been detected in the socket weld which attached the downstream side of the valve to the drain line.

The inspector reviewed test procedure No. TP 85-16 and test documentation and identified the following problems:

-- The data package indicates that valve MO 1201-2 was closed during the test. This valve must be open to pressurize the repaired weld on HO-65 during the test. The licensee stated that the data package was misleading and that this valve was verified open during the test. The data package was subsequently modified to reflect the actual valve position.

-- The location of the pressurizing connection to the test block is not specified by the procedure or indicated on the drawing. The licensee modified the test data package to indicate this connection.

The licensee indicated that pressure connections to test blocks were not normally indicated on ASME Class II and III hydrostatic test data packages. The positions of valves in the pressure connections were also not normally specified. The licensee agreed to indicate the location of pressure connections and the positions of pressure connection valves in future test packages.

The inspector had no further questions.

6. Maintenance and Modification Activities

a. Scope

The inspector reviewed the licensee's actions associated with maintenance and modification activities in order to verify that they were conducted in accordance with station procedures and the facility technical specifications. The inspector verified for selected items that the activity was properly authorized and that appropriate radiological controls, equipment tagging, and fire protection were being implemented.

A list of items reviewed is included at the end of this report in Attachment 1.

b. Findings

(1) The inspector reviewed the licensee's actions involved with maintaining the material condition of the Salt Service Water (SSW) System on a long term basis. The inspector held discussions with licensee quality control and engineering personnel, reviewed licensee documents including piping system inspection reports, and observed the system external condition.

Specific components or sections are being closely monitored and evaluations of overall system performance are being made. Ultrasonic measurements of wall thickness are being made on elbows (due to a damaged bitumastic rubber lining) and other system piping sections (due to general corrosion on the O.D.), and eddy current testing of heat exchanger tubes has been performed.

A September 26, 1983 licensee engineering department report (FS&MC 83-233) evaluated SSW pipe corrosion and concluded that "in no case has general or localized corrosion resulted in stresses in excess of those allowed by the FSAR. The corrosion will not affect the safe continued operation of PNPS nor will it affect the ability of the SSW system to perform its intended safety function". The general wall thickness was about 3 times greater than the minimum required.

Licensee personnel have performed recent walkdowns of the systems and with the aid of consultants have prepared a coating specification for the external piping. Plans include continuing to evaluate the system condition including cleaning, measuring (UT or visual) piping thickness, and coating. The results of these inspections will be used to determine the need for any future piping replacements.

The inspector concluded that the licensee's actions were acceptable. No additional concerns were identified.

(2) On February 9, 1985, the General Electric AKF field breaker for the "A" recirculation motor generator (MG) set failed to trip from a high differential overcurrent signal. The licensee then bench tested the ATWS trip function, and the breaker performed acceptably. The licensee disassembled the breaker and identified the following two problems:

-- The non-ATWS trip coil in the breaker was burned up.

-- An auxiliary switch that is connected to the breaker trip shaft had loose mounting bolts and was damaged.

The licensee believes that the loose auxiliary switch housing may have caused the switch to partially jam. If the switch jammed, the linkage from the switch to the breaker trip shaft could have prevented the breaker from opening and caused the trip coil to stay energized too long. The auxiliary switch may have then been damaged when the licensee manually opened the breaker prior to disassembly. This damage sequence, if true, could have prevented the breaker from opening on an ATWS signal. The licensee is planning to modify a spare breaker and to test it to determine whether this sequence is possible.

The licensee stated that the auxiliary switch on AK class breakers, including series 25 and 50 breakers, are used in the 480 volt safety busses. The licensee visually inspected all auxiliary switches on these breakers and found no problems. This item is unresolved, pending further licensee review (85-03-07).

(3) On February 14, 1985, the inspector observed the installation of temporary modification No. 85-11 to the alarm logic for the reactor protection system. This modification decreased the number of main turbine stop valves (SV) and main steam isolation valves (MSIV) which must close to generate the respective closure alarms. The modification had no effect on scram logic. The inspector reviewed the maintenance request (MR) No. 85-156 which was used for the work and discussed the modification with the workers who were installing it. The workers were observed to use appropriate instructions, use required tagging, and conduct appropriate post work testing.

The modification was installed in response to QA audit No. 84-34 on compliance with the technical specifications conducted between September 24 and October 10, 1984. The audit noted that the SV and MSIV functional test procedures (8.M.1-11 and 8.M.1-14, respectively) did not include tests of valve closure alarms. The finding was incorporated into Deficiency Report No. 1320 and transmitted to the station on November 5, 1984. The Deficiency Report identified the item as an instance of inadequate procedures to conform to the requirements of Technical Specification Table 4.1.1.

A Failure and Malfunction Report, No. 85-018, for the item and an Engineering Support Request (ESR) for the temporary modification were issued by the station three months later on January 28, 1985. On February 8, 1985, the item was identified as a violation of Table 4.1.1 and a recommendation was made to report the problem in a licensee event report (LER). The reactor was shut down on February 9, 1985 for repairs, and the temporary modification was made prior to restart. The licensee issued LER 85-002, "Inadequate Surveillance Procedure," on February 28, 1985.

As a result of the protracted time taken to evaluate and correct the QA audit finding, the licensee surveillance testing program did not ensure that MSIV and SV alarm functional tests would be conducted in accordance with technical specification requirements during January, 1985.

The MSIV closure alarm was functionally tested on January 4, 1985 by a pre-startup test (8.M.1-25). If the reactor had not been shutdown in January, this test may not have been conducted.

The SV closure alarm was not functionally tested in January. Failure to test the SV closure alarm prior to declaring the alarm operable on January 12, 1985 while the reactor was in the run mode and turbine first stage pressure was greater than 305 psig is an example of a violation of Technical Specification 1.0.V and Table 4.1.1 (85-03-05). This item was identified by the licensee, but will be cited because timely corrective action was not taken to prevent recurrence of the violation.

(4) The inspector reviewed the records for Maintenance Request (MR) 85-4-3, initiated on January 2, 1985, to replace the filters in the Control Room Environmental System. As part of the return to service process, surveillance test procedure 8.7.2.7, Measure Flow and Pressure Drop Across Control Room Environmental System, was performed on February 14, 1985. However, the testing was performed using Revision 4 of procedure 8.7.2.7. Revision 5 of the procedure had been approved July 27, 1984 and incorporated independent verification steps for returning the system to service.

On February 22, when informed of the lack of independent verification on MR 85-4-3, the licensee performed an independent verification.

The failure to exercise proper document control of test procedure 8.7.2.7 is a violation (85-03-11) of 10 CFR 50, Appendix B, Criterion VI, Document Control.

7. Health Physics Activities

a. On February 2 and 8, 1985, the licensee's Chief Radiological Engineer informed the inspector of unusual readings for five workers found during the routine processing of the January radiation dose monitoring badges. In all five cases, doses from pocket dosimeters and the badge third chip indicated agreement and much lower than the reported dose.

The inspector acknowledged the licensee's findings and actions, and forwarded this information to NRC:Region I personnel.

This matter will be included in additional NRC:Region I inspection followup to other similar badge problems (see Report No. 85-02).

b. The following information is included in this report to assist NRC management personnel in following radiation exposure at the station. The monthly personnel radiation exposure for January 1985 was 76.5 person-rems.

8. Independent Verification of Operating Activities

a. Program and Review

As part of the Procedure Update Program (PUP) and in response to TMI Action Plan Item I.C.6, the licensee committed to institute independent verifications of system configurations following maintenance or testing evolutions, and prior to startup from refueling outages. Specifically, both Nuclear Operations Procedure (NOP) 8301, Conduct of Operations, November 1, 1983, and station Procedure 1.3.34, Conduct of Operations, Revision 5 state the following:

> "When an ECCS, ECCS Subsystem, RPS or Primary Containment Isolation System is placed back into service after maintenance or testing has been performed, an independent verification ... that equipment has been placed in its proper configuration shall be made by a qualified person. In addition to this, all ECCS, PCIS, and RPS system alignments will be verified, in their entirety, prior to startup after each refueling outage with independent verification by a second qualified person. A qualified person is defined as a person who would be qualified to perform the initial component alignment."

In addition to the above procedures, the inspector reviewed those parts of station procedures 1.4.5, Tagging Procedure, and 1.5.3, Maintenance Requests, related to independent verification.

The provisions for independent verification of valve lineups and surveillance tests are in the valve checklists and test acceptance criteria sheets, respectively, of the applicable procedures.

The inspector reviewed four valve checkoff lists (procedure series 2.2.X), five surveillance tests of instrumentation (procedure series 8.M.X), and six surveillance tests of equipment (procedure series 8.X). All procedures clearly specified the equipment to be verified and its proper configuration, and provided signature blanks for the verification.

The independent verifications for maintenance are performed as part of the surveillance testing following the maintenance. The inspector reviewed eleven Maintenance Requests (MRs) completed subsequent to the plant startup in early January and the surveillance tests associated with the return to service of the applicable equipment.

The inspector reviewed the qualifications required to perform independent verifications. Past practice appeared to have utilized the judgement of the on-shift Nuclear Operating Supervisor who assigned the plant operators to remove tags as the criterion for qualifications. In a February 21, 1985, discussion, the Chief Operations Engineer stated that the Tour Qualification Program would be utilized to qualify new personnel for tagging and verification duties. The program involves approximately four weeks of instruction and on-the-job training for new plant operators and is performed by the Training Department.

b. Findings

The inspector found the following problems concerning the implementation of the independent verifications:

(1) On February 13, 1985 the Control Room Environmental System (CRES) was tagged out of service to replace charcoal and HEPA filters under MR 85-4-3. Following filter replacement, test procedure 8.7.2.7, Measure Flow and Pressure Drop Across Control Room Environment System, was performed on February 14, 1985 without an independent verification. This omission occurred due to use of an obsolete revision of the test procedure as described in section 6.b.4 above.

Further, on February 19, 1985, the CRES was tagged out of service to retorque the filter clamp nuts. No test and no independent verification was performed following the return to service of the CRES on February 19, 1985.

The inspector judged this to be an isolated personal error. On February 22, 1985 when informed of the lack of independent verification on MR 85-4-3, the licensee performed an independent verification.

(2) On February 8, 1985, main steamline drain isolation valve, MOV 220-1, was tagged out of service for motor replacement under MR 85-137. On February 9, 1985, MOV 220-1 was stroke tested and returned to service without an independent verification of proper

system configuration. The lack of an independent verification occurred due to the failure to properly complete test procedure 8.7.4.3 which provided for the verification on page A-3.

Further, MOV 220-2, the adjacent isolation valve was also tagged out of service and returned to service without any testing and without an independent verification.

(3) On January 7, 1985, shutdown cooling suction valve MOV-1001-43C (to RHR pump C) was tagged out of service under MR 85-33 for motor replacement. On February 9, 1985 following stroke testing, the valve was returned to service without an independent verification. Although not part of the LPCI configuration of RHR, it appeared to the inspector that independent verification should apply in this case because improper positioning of MOV 1001-43C could cross-connect the independent trains of LPCI.

(4) The MR documentation of tagging changes (i.e., red tag to green and white tag, removal of red tags, etc.) varied considerably and often involved crossing out the entire entry to indicate removal of the tag. This practice made understanding of the status and history of the tags difficult.

c. Conclusions

(1) The inspector concluded that the independent verification program lacks an adequate description of which equipment is covered. Procedures NOP8301 and 1.3.34 state that independent verification applies to "ECCS, ECCS Subsystem, RPS or Primary Containment Isolation System (PCIS)." However, this is not sufficiently detailed for the operating staff to consistently implement verifications. Further, the term "ECCS" is not generally used in Pilgrim procedures and this further complicates good understanding. The above verification scope is not clear concerning power supplies for verified systems or other important safety systems such as the Standby Gas Treatment System. This confusion regarding program scope is reflected in Finding 1 above (in that a verification was intended for the Control Room Environmental System, yet it is not part of the ECCS, RPS, or PCIS systems) and in Finding 3 concerning RHR system valve MOV 1001-43C. This item (85-03-08) is unresolved pending licensee action to detail the scope of the verification program.

(2) The inspector concluded that the methods for performing verifications are not specified in sufficient detail to enable consistent implementation concerning independence and to provide a common understanding of the expected verification process between personnel from operating, maintenance, training, and quality assurance staffs. Specifically, although procedures allow a direct or indirect method for verification, no mention is made as to what constitutes an "independent" verification. In Inspection Report 50-293/84-39, para-

graph 4.b(3), the inspector observed two plant operators concurrently performing and verifying the valve checklist for RCIC. The Chief Operating Engineer stated that this practice is inconsistent with staff instructions on independent verifications. Further, licensee Quality Assurance Surveillance Finding 85-12-1-1 provides additional examples of such problems. This item (85-03-09) is unresolved pending licensee action to clarify the acceptable methods of performing independent verifications.

(3) The inspector concluded that an effective means does not exist to verify proper system configuration when maintenance is performed on a system without a subsequent surveillance test or valve checklist, since verifications are incorporated into test procedures and valve checklists, but not incorporated into the tagging process. Examples are the nut retorquing described in finding 1 and MOV 220-2 described in finding 2. The Chief Operating Engineer and the Chief Maintenance Engineer stated that revisions of the tagging process are being evaluated to correct this problem and the documentation problem discussed in finding 4. The resolution of verification of maintenance work without surveillance testing is an unresolved item (85-03-10).

9. Followup to NRC Information Notice No. 84-86

The inspector reviewed the licensee's actions in response to receipt of NRC IE Information Notice No. 84-36, Isolation Between Signals of the Protection System and Non-Safety-Related Equipment, dated November 30, 1984.

Licensee engineering department report dated February 19, 1985 (NED 85-140) concludes that the problem identified at Waterford Unit 3 is not applicable to Pilgrim for several reasons.

-- The plant computer monitors the status of the RPS relays via an isolated contact, read by the computer's digital scanner which has no mercury wetted relays.

-- The RPS process sensor (level switches and pressure switches) are wired directly to RPS circuitry and no current loops are used.

-- The Pilgrim computer's mercury-wetted analog scanner (Honeywell 4020 system) has had a good operating experience with no relays ever failing in the closed position. The licensee believes this is due to two reasons: 1) operations in the millivolt range, thereby extending contact life, and 2) preventive maintenance on sluggish relays.

-- Plans for future process computer and analog trip system replacement will result in essentially double isolation with Class 1E systems.

The inspector judged the licensee's followup actions to be appropriate.

10. Management Meetings

During the inspection, licensee management was periodically notified of the preliminary findings by the resident inspectors. A summary was also provided at the conclusion of the inspection and prior to report issuance. No written material was provided to the licensee during this inspection other than a list of the RBCCW valve discrepancies included in Attachment I to this report.

ATTACHMENT 1

The following is a list of discrepancies identified during a walkdown of the RBCCW system. Also included is a list of surveillance and maintenance items reviewed during this period.

RBCCW Walkdown Discrepancies:

-- 1" -HO-66, loop "A" radiation monitor outlet was mistagged as 1" -HO-56, chemical addition tank outlet #2

-- Root valves to PI 4019 and PI 4013 were shown on the respective drawing but not numbered as (3/4" -HO-198 and 199).

-- The procedure check off list indicates that valve HO-198 is a root valve to PI 4012 while the drawing indicates that it is a root valve to PI-4019.

- A gauge locally labeled as PI-4051 is indicated as PI-4016 on the associated drawing.

-- A rubber hose was identified which connected the outlet from the "A" RBCCW heat exchanger to a decontamination water line. The licensee verified that the hose was isolated and was not pressurized. The licensee believes that the hose was used during repairs to the heat exchanger during the recent outage.

-- A 1" drain line adjacent to HO-193 on the RBCCW discharge crosstie line had no cap downstream of a block valve.

Portions of the following tests were reviewed:

-- Salt Service Water heat transfer operability test (TP-84-309) on January 29, 1985.

-- Operability test of valve MOV 220-1 (8.7.4.3) on February 6, 1985.

-- Post repair hydrostatic testing of the reactor vessel drain line (MOV Procedure TP 85-16) on February 17, 1985.

-- APRM functional tests 8.M.1-3 and 8.M.1-3.1 for December 1984 and January 1985.

-- Control rod block logic functional tests 8.M.2-3.6.1 through 3.6.4, conducted prior to startup in December 1984.

-- Rod block monitor functional test 8.M.2-3.1 and calibration 8.M.2-3.2 conducted prior to January 1985.

-- Turbine stop valve closure test 8.M.1-26 conducted prior to January 1985.

-- MSIV functional test 8.M.1-24 and 8.M.1-25 conducted prior to January 1985.

-- MSIV trip timing test 8.7.4.4 conducted between March 5, 1983 and February 15, 1985.

-- HPCI high steam flow trip test 8.M.2-2.5.1 conducted between November 9, 1982 and February 27, 1985.

-- Portions of reactor protection system channel response time tests 8.M.3-11.1 through 11.4 which tested turbine stop valve closure alarms and which were conducted in December 1984.

The maintenance and post work testing items reviewed included the following:

-- MR 85-6, Vacuum breakers; test No. 8.7.1.9
-- MR 85-33, MOV No. 1001-43C; test No. 3.M.4-10
-- MR 85-1,2,14, Standby Liquid Control System; test No. 8.4.1
-- MR 85-115, RCIC
-- MR 85-55,57, HPCI; 8.5.4.1, 8.5.4.4
-- MR 85-137, MOV No. 220-1; 8.7.4.3
-- MR 85-4-3, C.R. Environmental Filters; 8.7.2.7
-- MR 85-125, Adjust MSIV Timing or Limits; 8.7.4.4
-- MR 85-1-5, Adjust MSIV Timing; 8.7.4.4
-- MR 85-1-6, MSIV Timing Difficult and Varies; 8.7.4.4
-- MR 85-177, Received Annunciator "Reactor Scram Channel A" and Half Scram with No Accompanying Annunciator Indicating Reason for Occurrence
-- MR 85-160, Repair Leak in Vessel Drain Line Weld' TP 85-16
-- MR 85-169, "B" Rod Block Monitor is Inoperable
-- MR 85-140, Open and Inspect Bearing on "A" Recirculation Pump