U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No: 50-245/87-12

Docket No: 50-245

License No: DPR-21

Licensee: Northeast Nuclear Energy Company
P. O. Box 270
Hartford, Connecticut 06141-0270

Facility: Millstone Nuclear Power Station, Unit 1

Inspection at: Waterford, Connecticut

Dates: June 23, 1987 through August 10, 1987

Inspectors: Geoffrey E. Grant, Resident Inspector
Eben L. Conner, Project Engineer

Approved by: Ebe McCabe 8/20/87
E. C. McCabe, Chief, Reactor Projects Section 3B Date

Summary: Report No. 50-245/87-12 (June 23 to August 10, 1987)

Areas Inspected: This inspection included routine NRC resident (104 hours) and region-based (79 hours) inspection of previously identified items, plant operations, surveillance, maintenance, radiation protection, physical security, fire protection, allegations, a wide variety of outage activities and various ESF actuations.

Results: No violations were identified. The licensee's fulfillment of a commitment to the NRC regarding IEB 84-03 supplemental information is an unresolved item (see Detail 4.4). The licensee has taken additional correction action on previously identified licensee event reporting discrepancies (see Detail 12). The inoperability of the Standby Gas Treatment System on July 24 demonstrated a lack of recognition of the effects of maintenance actions on interrelated systems (see Detail 13). The worker contamination by a hot particle on August 4 demonstrated a weakness in personnel frisking techniques and radiological cleanliness (see Detail 15). Three Unresolved Items, deriving from Potential Enforcement Findings identified in IR 50-245/87-09, are opened in this Inspection Report pending further licensee analysis and documentation (see Detail 23).

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DETAILS

1. Persons Contacted

Mr. S. Scace, Station Superintendent
Mr. J. Stetz, Uni: _ Superintendent

The inspector also contacted other licensee employees.

2. Summary of Facility Activities

Unit 1 was shutdown for the Cycle 12 refueling and maintenance outage during this period. The status of major outage activities follows:

-- Jet Pump Instrumentation Nozzle - the existing assemblies, degraded by Intergranular Stress Corrosion Cracking (IGSCC), were replaced by new penetration assemblies resistant to IGSCC. Flow indication for nozzle "K" was lost due to apparent blockage after welding instrument lines to the new assemblies (see Section 11 for details).

-- Process Computer - replaced with new unit that includes the Safety Parameter Display System (SPDS) and a microprocessor-based Rod Worth Minimizer (RWM).

-- Core Reload - the full core was off-loaded to facilitate maintenance. The Cycle 12 core contains 196 fuel assemblies with GE8B fuel, three replacement control rods, and new local power range monitors (LPRMs) with GE NA300 detectors.

-- Inservice Inspection (ISI) - ultrasonic testing (UT) inspection was done on 160 stainless steel piping welds in the recirculation, shutdown cooling, reactor water clean-up (RWCU) and isolation condenser (IC) systems. Additionally, 45 welds in the non-safety-related part of the RWCU system were UT inspected. ASME required UT, penetrant testing (PT) and magnetic testing (MT) of 115 items were completed. Automated UT inspections of ten reactor vessel nozzle-to-vessel welds and nozzle inner radius inspections were done. Remote visual inspection of the core spray (CS) spargers, intermediate range monitor/source range monitor (IRM/SRM) dry tubes, moisture separator and reactor vessel was accomplished. Shroud holddown bolts were remotely UT'd per GE Service Information Letter (SIL) 433. Feed and condensate piping were tested for thickness. Visual Examination (VTs) of over 1,000 piping hangers was done to fulfill a 1985 outage commitment. UT inspection of the drywell shell was performed in response to Generic Letter 87-05.

   The IGSCC weld inspections found one rejectable weld indication on the Recirculation System B-loop manifold-to-end cap weld. A full structural weld overlay was applied in accordance with NUREG-0313, Rev. 2 guidelines. Inspection of an Isolation Condenser piping weld detected base metal inclusions in a two foot length of pipe. This section of pipe was replaced. By letter dated August 7, 1987, NRR accepted the licensee's IGSCC inspection and repair results.

-- MOV Replacement - the motor operators on RR-2A and 2B and IC-2 were replaced with Limitorque operators to fulfill EEQ requirements.

-- 10 CFR 50 Appendix R - modifications were made to Unit 1/Unit 2 backfeed, the control room Halon system, alternate shutdown cooling, emergency lighting, hydrogen system piping, reactor pressure and level instrumentation, radio repeater back-up power, and the control rod drive (CRD) pumps.

-- Main Turbine Rotor - replacement of the "B" Low Pressure rotor with an improved monoblock design rotor was completed.

-- Overcurrent Trip Device - replacement of the electro-mechanical trip devices on 30 safety-related 480V breakers with "Micro Versa" solid state trip devices was completed to provide a more accurate and repeatable trip setting of these breakers.

-- Torus to Drywell Pumpback System - a modification was made to allow the drywell nitrogen compressor to take a suction on the torus and discharge to the drywell. This will reduce the need to frequently vent and purge to maintain the required 1 psid between the torus and drywell.

-- Standby Liquid Control System - an upgrade to use Boron-10 enriched sodium pentaborate was completed to fulfill requirements of 10 CFR 50.62 (ATWS).

-- Chemical Decontamination - the recirculation and reactor water cleanup (RWCU) systems were decontaminated in order to save approximately 400 man-rem.

-- Containment Integrated Leak Rate Test - (see Section 19).

-- IEB 85-03 Response - testing of safety-related motor operated valves was completed (See Section 4.3).

-- Insulation - replacement of cracked "NORYL" insulation on safety-related bus work was completed.

-- Seismic Hangers - modifications to about 70 of the 160 seismic hangers left to do by 1990 were made on various CAT I Systems.

-- Ventilation - modifications were made to connect Feedwater Coolant Injection (FWCI) and condensate pump area ventilation coolers to a source of emergency power.

3. Operational Safety Verification

The inspector observed plant operations during regular and backshift tours of the following areas:

Control Room	Cable Vault
Reactor Building	Fence Line (Protected Area)
Diesel Generator Room	Intake Structure
Vital Switchgear Room	Gas Turbine Building
Turbine Building	Drywell/Torus

Control Room instruments were observed for correlation between channels, proper functioning, and conformance with Technical Specifications. Alarm conditions in effect and alarms received in the control room were reviewed and discussed with the operators. Operator awareness and response to these conditions were reviewed. Operators were found cognizant of board and plant conditions. Control room and shift manning were compared with Technical Specification requirements. Posting and control of radiation, contaminated, and high radiation areas were inspected. Use of and compliance with Radiation Work Permits and use of required personnel monitoring devices were checked. Plant housekeeping controls were observed including control of flammable and other hazardous materials. During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication of equipment status. These records included various operating logs, turnover sheets, tagout and jumper logs, and Plant Information Reports. The inspector observed selected actions concerning site security including personnel monitoring, access control, placement of physical barriers, and compensatory measures. Inspections of the control room were performed on weekends and backshifts including July 8, 9, 10, 13, 14, 15, 16, and August 2, 3, 4, 7, and 9. Operators and shift supervisors were alert, attentive and responded appropriately to annunciators and plant conditions. A wide variety of outage activities were in progress during these inspections. In all cases, operators and supervisors maintained a professional control room atmosphere.

4. Licensee Actions on Previously Identified Items

4.1 (Closed) VIO 50-245/87-05-01, Primary Containment Isolation Valves

By letter dated June 25, 1987, the licensee responded to the IR 50-245/87-05 violation for failure to include containment atmosphere sample line isolation valves in TS Table 3.7.1. Application for a Technical Specification change was made on April 28, 1987. This application to change TS Table 3.7.1 is being reviewed by the NRC.

In the reply, the licensee stated that, in addition to adding the specified PASS valves to the table, they initiated an extensive effort to compile a complete and up-to-date listing of containment isolation valves. This caused a delay in the submittal (see Inspection Report (IR) 50-245/87-05 for details).

In discussions, the licensee stated that they had identified the problem with timeliness of submittals and that corrective actions were underway at the time of the violation. The corrective actions, such as monthly status reports, commitment tracking upgrades, emphasis on accurate identification of commitments, and reorganization and augmentation of the licensing staff to reduce backlog are appropriate and address the issue. This item will be further reviewed during routine inspections.

4.2 (Closed) VIO 50-245/87-05-02, Technical Specification (TS) Snubber Lists

By application dated May 15, 1987, the licensee proposed to delete Tables 3.6.1a and 3.6.1.b (listing of hydraulic and mechanical snubbers) from the TSs and to make other changes to TS 3.6.1. This was corrective action for violation 50-245/87-05-02. The proposed TS change was reviewed by the NRC and is being processed for issue. No safety concern is outstanding (see also Section 7).

4.3 (Open) IE Bulletin 85-03, Motor Operated Valve (MOV) Common Mode Failure During Plant Transients Due to Improper Switch Settings

The licensee's June 11, 1986 response addressed the six required actions related to the subject bulletin. This response was reviewed for timeliness and content in IR 50-245/86-17.

IE Bulletin 85-03 specifies that, for MOVs in the high pressure coolant injection/core spray and emergency feedwater systems (RCIC for BWRs) that are required to be tested for operational readiness in accordance with 10 CFR 50.55a(g), licensees develop and implement a program to ensure that operator switches are selected, set, and maintained properly. The licensee's reply concluded that, for Millstone 1, this includes the Feedwater Coolant Injection (FWCI) and Isolation Condenser (IC) systems, only. They interpret that only high pressure core spray systems require action, thus, the low pressure core spray system at Millstone 1 was not included in their program. This is acceptable to the NRC. The bulletin provisions are addressed as follows.

a. Design Bases for Motor Operated Valves (MOVs)

The licensee was to review and document the design basis for each MOV including the maximum valve differential pressure expected during both opening and closing for both normal and abnormal events. The licensee identified 5 IC MOVs and 5 MOVs related to FWCI. The specified design differential pressures for all 10 valves were equal to or greater than the normal and abnormal event maximum differential pressures. Therefore, this bulletin action was satisfied.

b. Translate the Specified Design Differential Pressure to the Correct MOV Switch Settings

The licensee's response outlines a plan to determine the proper switch settings using a combination of analytical and empirical data. The inspector found that, although this engineering had been performed, it was difficult to review during the outage. The review will be performed after November 1987.

c. Testing of MOVs to Insure Valve Switch Settings

The licensee committed to stroke test each valve, to the extent practical, to verify that the settings defined have been properly implemented. To this end, NNECO has purchased Motor Operator Valve Analysis and Test System (MOVATS) equipment and initiated MOV testing at Millstone 1. The inspector reviewed Special Procedure 87-1-15, Procedure for Testing Limitorque MOVs Using MOVATS and observed the physical testing of several MOVs. The licensee stated that important MOV findings/resettings will be provided with the final report.

d. Review/Revise Procedures to Ensure Correct MOV Switch Settings

The licensee committed to review and revise procedures as necessary to ensure that correct switch settings are determined and maintained throughout the life of the plant. The licensee is working to have the necessary procedure changes completed by November 1987.

e. Report the Results of MOV Design Basis Review and Provide the Schedule for Corrective Actions

The licensee's June 11, 1986 letter provides the results of MOV design basis review and commits to complete the other actions for Millstone 1 by November 1987. The inspector will review the data after the final report is received. The licensee has established a coordinated and comprehensive MOV testing program that addresses the concerns of IEB 85-03.

4.4 (Open) IE Bulletin 84-03, Reactor Cavity Water Seal

IEB 84-03 informed licensees of an incident involving failure of a refueling cavity water seal and requested various actions to assure that fuel uncovering during refueling remains unlikely. By letter dated November 29, 1984 the licensee responded, as requested, to IEB 84-03. This detailed response analyzed each of the required evaluations as well as additional areas concerning refueling activities. This submittal described, in detail, Unit 1 dual stainless steel bellows seals along with comparisons to Haddam Neck's pneumatic seals. A postulated failure of the refueling cavity pool seals was addressed. Because a definitive resolution of what constitutes a credible seal failure was unavailable, a postulated catastrophic 360 degree failure was used as a basis for determining consequences. The licensee committed to investigating and refining the possible failure mechanisms and updating the information in a future submittal. The analysis used in this submittal considers all of the possible consequences of seal failure based on worst case. Conclusions reached in the submittal were conservative and logical. They included:

-- Although catastrophic failure of a pool seal is extremely unlikely, it was assumed as the basis for the evaluation. A catastrophic failure could result in insufficient time to allow the operators to move fuel to a safe location. As such, an evaluation of the seal assembly failure is to be performed to determine a realistic failure scenario, its consequences and probability of occurrence. The remainder of the refueling cavity seal failure analysis was based upon all irradiated fuel being placed in either the reactor vessel or spent fuel pool subsequent to seal failure.

-- All irradiated fuel bundles in the spent fuel storage racks and reactor vessel remain covered following termination of draindown.

-- Sufficient time is available prior to active fuel uncovery due to boiloff to provide a source of makeup water to the spent fuel pool.

-- Failure of the seal initiated by dropping of a fuel assembly was to be evaluated. This failure was not expected to be a cause for concern since, during fuel movement, the seals are protected from the effects of a fuel drop by the "cattle chute".

-- Dose rates within the control room would be acceptably low for continued occupancy with offsite doses well within the limits of 10 CFR 100. Limited access to the refueling floor would be possible for recovery activities.

The licensee's submittal included a commitment to further evaluate various aspects of the concerns. These additional evaluation items formed Attachment No. 5 to the submittal and included the following for Unit 1:

-- Perform a failure analysis of the refueling cavity seals to determine the most limiting credible failure scenario. Information contained in Attachment No. 1 will be revised, as necessary, based upon the results of this analysis.

-- Determine if any potential spent fuel pool or refueling cavity drainage paths exist from events other than from a refueling cavity seal failure, and implement any corrective actions deemed necessary.

-- Implement a new or revised emergency operating procedure which identifies necessary operator actions in response to a loss of refueling cavity water inventory. This emergency operating procedure will include consideration of the potential existence of reactor vessel internals in the refueling cavity.

-- Demonstrate that all necessary fuel handling actions required by the emergency operating procedure can be performed within the time interval available. This time interval will be identified once a credible cavity seal failure scenario is determined and any other existing refueling cavity or spent fuel pool drainage paths are evaluated.

-- Evaluate the effects, if any, on the refueling cavity seals of a fuel assembly drop on the "cattle chute," and implement any corrective actions deemed necessary.

-- Evaluate the addition of a permanently installed makeup line from the condensate transfer or fire water system to the spent fuel pool, and determine a schedule for any corresponding plant modifications.

-- Determine whether a dedicated empty space in the spent fuel storage racks to accept spent fuel in an emergency is appropriate, and implement any corrective actions deemed necessary.

-- Revise sipping procedures to assure adequate cooling of spent fuel in a sipping can during a loss of refueling cavity water inventory.

-- Evaluate the installation of a water level indicating and/or alarming instrument which uses direct measurement of spent fuel pool water level, or modification of existing instrumentation, and implement any corrective actions deemed necessary.

-- Review refueling procedures to assure adequate operability requirements for instrumentation needed to detect a loss of refueling cavity water inventory.

The licensee further stated in his November 1984 submittal:

> "Although the attached information represents a significant effort to date, further actions are necessary to confirm the acceptability of spent fuel manipulations during refueling operations. Additional items scheduled to be completed prior to moving fuel at the next refueling outages at Millstone Units No. 1 and 2 and the first refueling outage at Millstone Unit No. 3 are delineated in Attachment No. 5. We currently plan to submit supplemental information to the NRC Staff regarding the resolution of these items on a schedule consistent with the completion of these items."

The licensee has had two refueling outages at Unit 1 since the 1984 submittal (Fall 1985 and Summer 1987) but has not submitted any supplemental information to the NRC concerning the resolution of these items.

The inspector reviewed the status and completeness of the ten licensee identified action items. Most of the required evaluations and applicable corrective actions could be verified as having been completed prior to or during the 1985 refueling outage. The inspector could not identify in any refueling procedure the implementation of a dedicated empty space in the spent fuel storage racks to accept fuel in an emergency.

Initially, licensee evaluations and actions on IEB 84-03 were conservative, well-engineered and timely. The licensee's follow-up fulfillment of their commitment to the NRC to supply supplemental information is an unresolved item (UNR 50-245/87-12-01).

4.5 Closed) IE Bulletin 80-25, Operating Problems with Target Rock Safety-Relief Valves

IEB 80-25 notified licensees of various problems associated with operation of Target Rock Safety-Relief Valves (SRVs). Applicable licensees were to respond to three action items: (1) initiation of appropriate quality control procedures and verification of two-stage SRV operability, (2) procedure changes to require various corrective actions in the event of SRV failure and, (3) review of the SRV pneumatic supply system. The licensee's response to IEB 80-25 dated March 16, 1981 adequately addressed action items (1) and (3), and also indicated that procedure changes would be made to address the requirements of action item (2). The inspector reviewed Maintenance Procedure MP 717.1 "Maintenance of Target Rock Relief Valves" and verified that the requirements of IEB 80-25 action item (2) have been incorporated.

5. Misorientation of Fuel Assembly

On June 12, 1987, while off-loading Core 11, fuel assembly LY2729 in core location 43-18 was found rotated ninety (90) degrees from its proper orientation. The inspector reviewed Plant Incident Report (PIR) 1-87-36, dated June 12, 1987. A review of the previous core load video tape verified the misalignment. The licensee's corrective actions were: (1) evaluate cycle specific effects of misoriented fuel assembly on the other fuel assemblies and other core parameters; and (2) revise RE 1077 prior to next use to require separate reviews and sign-offs for bundle orientation and bundle serial number confirmations.

5.1 Cycle Specific Effects

Misorientation of a fuel assembly was analyzed by GE as part of cycle-specific reload analysis. For Cycle 11, the worst case bundle orientation error would have resulted in a change in Minimum Critical Power Ration (MCPR) of 0.17. The GE calculational results, documented in GE letter ADV 87194 (June 18, 1987), show that the misoriented bundle would have to develop an MCPR of 1.66 or less for the limiting transient (load rejection without bypass flow) for the transient to put it on or below the TS safety limit of 1.07. Exposure accounting data for Cycle 11 shows that this bundle, LY2729, used in Cycles 9-11, never experienced a CPR of less than 2.38. Therefore, this bundle would not have exceeded the safety limit had the limiting transient occurred. Fuel assembly LY2729 will not be reused in future cores. The inspector had no further questions on this analysis.

5.2 Revise RE 1077

The inspector confirmed that RE 1077 has been revised to add Step 7.8 which states; "An independent review shall be made to verify bundle orientation. This reviewer may not be involved in any other core verification activity." This change, Revision 5 to RE 1077, received PORC approval at meeting No. 1-87-75. The revised RE1077 was implemented for the Cycle 12 core load. The inspector had no further questions on this item.

6. Uncoupled Control Rod

The licensee originally planned to replace four Control Rod Blades during this outage due to imminent rod burnout limits. Control rod burnout represents the partial loss of neutron absorption capability as the rod ages. Three blades were successfully replaced. Control Rod Blade 26-43 was unable to be uncoupled for removal. A number of standard and non-standard methods were used over several days in attempts to uncouple the rod. At the point that further attempts would begin unfavorably impacting the outage schedule, the licensee determined that the rod could remain in operation for the next cycle. Alternative methods of rod removal would be studied during this interval. The licensee requested that General Electric analyze the effects of operation with this rod remaining in the system. Preliminary analysis shows that blade lifetime will not be exceeded for at least one effective full power month. Current licensee's plans are to conduct detailed calculations of post-burnout blade effects (including impact on shutdown margin) during the next month. The inspector will review the results of the final analysis during routine inspection.

7. Snubber Inspection

In accordance with Technical Specification Surveillance Requirements, visual inspection of all snubbers and bench test of 10% representative samples of each type of snubber, mechanical and hydraulic, were to be performed during the current outage.

7.1 Visual Inspection

The inspector observed visual inspection of Bergen-Paterson (B-P) and Grinnell hydraulic snubbers and Pacific Scientific mechanical snubbers inside the drywell. The inspections were performed in accordance with

MP 739.5, Inspection of Hydraulic Snubbers, and MP 739.6, Mechanical Snubber Visual Inspection. Data collected was recorded on the appropriate maintenance forms. Because the Bergen-Paterson snubber design uses a piston-spring reservoir with a position indicating rod, its reservoir level is calculated using MP 739.5 instructions. The Grinnell reservoir is clear plastic (no piston) and the level is determined directly.

The overall condition of the snubbers observed was good. Hydraulic snubbers are rebuilt at least once per five years, but may be selected for bench testing and rebuilding earlier based on the visual inspection. The visual inspections are performed by maintenance engineers. The inspector had no questions on visual inspection techniques.

7.2 Bench Testing

The inspector observed the bench testing of hydraulic snubbers including lockup and bleed rate determination in the compression and tension modes. The test was performed on an ITT Grinnell test bench. For this outage, a total of 3 Grinnell and 6 Bergen-Paterson hydraulic snubbers failed the bench test. All of these failures were due to excessive bleed rates. These failures required the bench testing of all hydraulic snubbers in accordance with TS 4.6.I.3.

These activities were controlled by:

-- SF 207, Millstone Inspection Plan;

-- MP 739.3, Mechanical and Hydraulic Snubber Removal and Installation;

-- SP 781.1, Hydraulic Snubber Functional Test; and

-- MP 739.1, Hydraulic Snubber Functional Test and Repair.

Data was recorded on the appropriate maintenance forms. Snubber removal, testing, rebuilding, retesting and installation was supervised by an upgraded lead mechanic, with a vendor representative on-site in the last weeks of the outage. The inspector had no further questions on testing and rebuilding snubbers.

8. Main Steam Relief/Safety Valve Inspection

The six (6) main steam safety/relief valves (SRVs) were removed early in the outage and sent to Wyle Laboratories for bench testing. The test data follows:

Safety/Relief Valve Set Pressure Drift Test Results - Lift Pressure

SRV No.	TS Limit	First	Second	Third	Fourth	% Drift
1036	1095	1114	1119	1116	----	1.7
1037	1125	1174	1133	1131	1128	4.4
1039	1110	1610*	----	----	----	45.0
1041	1125	1132	1142	1138	1133	0.6
1042	1125	1177	1138	1134	1133	4.6
1077	1125	1156	1130	1127	1125	2.8

*Estimated lift set pressure.

The inspector reviewed a copy of Wyle Test Procedure No. 1025. This procedure addresses Calibration of Test Equipment, Measurements and Tolerances, Personnel Certification, and Receipt, Handling, Testing, and Documentation of SRV testing. The procedure is very detailed.

Based on the data, only SRV 1041 lifted within the +/- 1% TS requirement and SRV 1039 did not lift within the 1250 psig capacity of the test stand. The licensee requested GE to evaluate the effect of the as-found set pressures for vessel integrity considerations. This information was received from GE as EAS-84-0787, dated July 1987. The GE analyses are based on one SRV out-of-service coincident with the drifting of the opening setpoint of the remaining 5 SRVs to 5% above the TS limits. The analysis considers the thermal limits (MCPR), LOCA limits (large and small breaks considered), and overpressure protection limits (ASME Boiler and Pressure Vessel Code). This report concludes that, based on as-found SRV conditions, Cycle 11 operation was within the plant safety limits. The inspector had no further questions on this issue.

9. Torus Repair/Painting

One of the major outage jobs, both in time and radiation exposure, was the torus repair painting. The work was performed by a consultant under Utility and Industrial Inc. (U&I) Form No. 101, Torus Repair Painting. Areas of the torus where paint blisters or peeling existed were scraped and/or sanded down to bare metal or intact zinc primer. If bare metal was reached, a Tnemec 66-1211 primer (colored gray) had to be applied within 3 hours. Areas where the old zinc primer was intact were washed with a 10% chlorine solution to kill any bacteria and rinsed with demineralized water. The primed areas, both freshly primed and old zinc primed, received a 3 to 5 mill coat of Tnemec 66-1211 Expoxaline (colored white). Painting could only be performed when the relative humidity was less than 80%. This greatly delayed the job due to high humidity weather conditions.

Twelve of the 16 bays were completed using the U&I 101 procedure. To reduce the job time and exposure, U&I 101 Change 4 allowed a reduction in surface preparation to remove loose paint flakes only and decreased the coating thickness to 1.5 to 3 mils by mixing the primer with 10% Tnemec Paint thinner. Change 4 was authorized for 4 bays and for below the normal water level. The area at and above the normal water level had surface preparations and painting the same as the entire 12 bays. The licensee plans to review the area, where surface preparation was reduced and to inspect the entire torus during the next refueling outage.

The inspector observed the torus work near completion of surface preparation and painting. QC was active in monitoring surface preparation, determining torus relative humidity, and measuring the paint thickness (done while wet with depth gauge). QC inspections were in accordance with SF 207, Rev. 5 (original plan) and 6 (reduced plan). The inspector observed the licensee's closeout inspection of the torus. Minor areas above the water line were touched up with paint. The inspector had no further questions.

10. Torus-Drywell Vacuum Breaker Indication

On November 10, 1985, while performing surveillance of the torus to drywell vacuum breakers, the alarm micro-switches were found to be out of calibration. This condition would have caused a loss of the alarm required by TS 3.7.A.5(3) if the valve disc lifted more than 0.075 inch. LER 85-025 reported this event and stated that an engineering evaluation is underway to ascertain the feasibility of micro-switch contact area design change. The inspector reviewed the response to PIR 85-74, Torus to Drywell Vacuum Breaker Alarms Out of Calibration, Change No. 1 to MP 712.1, Vacuum Breaker Valve Inspection and Repair, SP 777.1, Rev. 6, Pressure Suppression Chamber Drywell Vacuum Breaker Functional Test, and PDCR 1-13-86, Vacuum Breaker Alarm Switch Modification. The new adjustment set screw design along with the procedure changes address past calibration problems. The inspector had no further questions.

11. Loss of Jet Pump "K" Flow Indication

On July 13, 1987, following completion of the replacement of all 20 jet pump instrumentation nozzle assemblies with penetration seals fabricated of materials and welds resistant to IGSCC, no flow indication could be obtained for jet pump "K". Flow indication was available for the remaining 19 jet pumps. Although TS 3.6.G.3 allows continued operation with loss of flow indication from one (1) jet pump, all 20 jet pumps must have flow indication for reactor start-up from cold shutdown. By letter dated July 23, 1987, the licensee requested an emergency TS change to authorize restart from the current outage with 19 of the 20 jet pump flow indications operable. NRR issued Amendment No. 7, dated August 6, 1987, authorizing reactor startup for Cycle 12 operation with 19 of the 20 jet pumps with flow indication.

The inspector monitored licensee corrective actions following discovery of the blockage. He attended the July 21, 1987 PORC and NRB meetings and was provided a copy of the application for TS change. The inspector commented that inclusion of ISI data, data from instrument line pressurization to 6000 psi (action to clear blockage), and minor wording changes would improve the application. The inspector reviewed licensee analysis confirming that the 6,000 psi pressure used to attempt to clear the "K" jet pump instrumentation line blockage would not produce stresses in excess of allowable stresses for each of the line segments which were pressurized. The licensee's calculated maximum allowable stress for the one-inch Schedule 80 piping (largest diameter - lowest allowable stress) was 6110 psi. The inspector had no further questions on this issue.

12. Licensee Event Reporting

Inspection Reports 50-423/86-21, 50-245/86-13, and 50-423/87-05 address a problem with the Millstone event reports to the NRC Incident Response Center. The problem involves the use of the term "General Interest Event", a term not defined by the NRC and similar in sound to the NRC's "General Emergency" event class. In a March 12, 1987 meeting with Millstone management, corrective actions including revision of EPIP Form 4112-1 (General Interest Event on front page) and training of shift personnel were proposed by the licensee to resolve the issue.

Recent information indicates that, of the 44 events reported since January 1, 1987, at least 12 reports had classification problems. These 12 reports (computerized event summaries) were discussed with site management on July 21 and 24, 1987. At the July 24 exit meeting, the licensee provided a copy of a July 23, 1987 Instruction to Units 1, 2, and 3 Operation Superintendents, Shift Supervisors and Shift Supervisor's Staff Assistants. This instruction states in part: "Effective immediately the phrase 'General Interest Event,' as well as the Connecticut State Posture codes shall not be used to describe events to the NRC duty officers even as amplifying information." To complete action on this issue, the licensee will document the corrective actions taken by letter to the NRC. The inspector had no further questions on this issue.

13. Failure of Standby Gas Treatment System

On July 24, 1987, while in the refueling mode and during actual fuel movement, both trains of the Standby Gas Treatment System (SGTS) were found inoperable during maintenance on SGTS primary containment isolation valve AC-10. Neither SGTS train's normal suction valve from the secondary exhaust plenum, SG-1A and SG-1B, would open because the AC-10 limit switch (single limit switch with dual contacts) was in the intermediate position due to AC-10 being removed. Fuel movement was suspended until a closed signal for valve AC-10 was inserted to allow proper SGTS operation. The licensee estimated that the SGTS was inoperable for about 8 hours prior to its discovery. During this period of time, although SG-1A and 1B would not have opened, the SGTS would have responded to automatic or manual initiation signals. Because the SGTS inlet damper from the steam tunnel was open and the door to the steam tunnel was open, a flow path existed through the Reactor Building, the steam tunnel, and SGTS. This flow path was demonstrated to exist when the licensee manually started the SGTS and approximately 900 scfm of flow was observed. However, failure of the SGTS to be fully operable during fuel movement is not in accordance with TS 3.7.C.1.

The AC-10 limit switch is interlocked to prevent drywell or torus radioactivity from entering the secondary exhaust plenum. That interlock requires AC-10 to be closed before SG-1A and/or SG-1B can be opened.

System inoperability was discovered when manual SGTS operation was attempted during outage maintenance on the normal ventilation system. The licensee was requested to review this event for SGTS vulnerability to single failure. No safety-related purpose for the AC-10 interlock was found. Any radioactivity that went from the drywell or torus into the exhaust plenum would be held in the plenum and detected by radiation monitors causing automatic isolation before release. Additionally, the release of drywell pressure buildup via AC-10 is an infrequent evolution. Based on the licensee's investigation, corrective actions were to defeat the AC-10/SG-1A, SG-1B interlock using a jumper. A permanent correction under the design change program is being processed for implementation at a later time. The licensee is reviewing reportability under 10 CFR 21. Additionally, an operator is to be assigned to AC-10 valve control during all periods when it is open. These actions will effectively remove SGTS vulnerability to a potential single failure while maintaining control of possible cross-contamination between the drywell/torus and the reactor building.

The licensee's test demonstrated that, for the circumstances existing when AC-10 was removed, the SGTS could have effectively maintained a negative pressure in secondary containment. Also, the ability to actuate normal secondary containment isolation was not affected. The ability to maintain negative pressure and isolate normal ventilation effectively negated the potential for higher than expected radiation releases and releases from other than prescribed routes. This data, plus the fact that the problem was licensee-identified, appropriately reported, immediately corrected, and not connected to any previous violation, resulted in the determination that no Notice of Violation will be issued in this instance.

14. Allegation of Improperly Labeled Box of Radioactive Material

On July 23, 1987, the Resident Inspector's Office received an anonymous call on the plant line. The individual alleged that there was an unmarked box containing radioactive material at the far end of the turbine hall. No other data could be elicited. The inspector, the acting Unit 1 HP Supervisor, and an HP technician then surveilled the clean areas adjacent to the turbine hall. All containers of radioactive material observed in these areas were properly marked. Turbine components and tools in the roped-off contaminated work area were numerous. However, control of contamination in this and surrounding areas was good. HP technicians were permanently assigned to this area during the turbine overhaul. In addition, the rail entrance area at ground level was examined. About one hour was spent on these checks. Nothing out of the ordinary was found. This allegation was not substantiated.

15. Radiological Control Problems

On August 4, 1987, a worker was found to be contaminated with a hot particle (minute particle of radioactive material with a high specific activity) as he exited through the portal monitor at the security access point. The hot particle, located on the skin of the worker's back, was removed shortly after identification. The worker, an I&C technician, had been working in the Unit 1 drywell and torus earlier that shift.

Subsequent analysis of the hot particle identified it as being composed of Co-58 and Co-60. Preliminary dose estimates indicate an exposure to the worker's skin of 6.2 rem. This skin exposure, added to his previous quarter's exposure of 0.2 rem, resulted in a total skin exposure of 6.4 rem (within the regulatory limit of 7.5 rem/qtr). Based on the location of the particle, the licensee concluded it was transferred to the worker via cross-contamination from inadequately cleaned protective clothing.

The licensee's immediate corrective actions included the following:

-- Mandatory presence of an HP technician (for help in frisking workers) at all Unit 1 radiation work areas.

-- A buddy system frisk requirement at Units 2 and 3.

-- Suspension of on-site dry cleaning of PCs.

-- Placement of new Eberline PCM-1A at the exit to the reactor building.

-- Assigning HP technicians at security gates during high traffic times.

Although these actions appear to be sufficient to prevent recurrence of extended personnel exposure to hot particles, the licensee needs to concentrate on improving radiological control practices. As illustrated in IR 50-245/87-15, programmatic and personnel error problems have existed in this area. Within one week of the IR 87-15 exit meeting where these issues were discussed with plant and site management, three instances of unlocked and unattended high radiation area doors were discovered by plant personnel. This appears to be a particularly persistent problem area where past licensee corrective actions have been ineffective. The licensee is in the process of formulating and implementing a comprehensive corrective action program to address these deficiencies. The resident inspector and region-based specialists will continue review the effectiveness of licensee's actions on such matters during routine inspection activities.

16. Bomb Threat

On July 24, 1987, the Connecticut State Police telephoned an apparent bomb threat to the Unit 1 Control Room. Site security surveillance was increased. This incident began when a man tried to phone the Millstone site with telephone operator assistance, identifying himself and saying it was easy to get to the Control Room and blow it up. The operator informed the State Police. They went to the man's residence, reportedly found him intoxicated and harmless, and arrested him for falsely reporting an incident. The individual is a former contractor (C.N. Flagg) radiation worker who was laid off because he could not pass pulmonary testing. His site access had been terminated on July 6, 1987. The inspector had no further questions on this item.

17. Foundation Bolts for ESF Pump Base Plates

On July 7, 1987, the licensee notified the NRC that the Core Spray (CS) and Low Pressure Coolant Injection (LPCI) system pump foundation hold-down bolts (excepting the "A" LPCI pump) were shorter than specified by the design. Visual examination of an embedded CS pump foundation bolt had confirmed previous ultrasonic indications of short bolts. This information was extrapolated to the other CS and LPCI pumps. The licensee added 2 support plates per pump using 9 and 12 inch Drillco Maxi-bolts for the CS and LPCI systems, respectively. These additional plates were designed to support the pumps independent of the old supports, which were left in place. The inspector talked to the primary engineer and reviewed this installation. To ensure the problem was localized to the CS and LPCI systems, the licensee performed UT inspections of all safety-related pump foundation bolts. Results indicated that all other foundation bolts were of the specified design length. The inspector had no further questions.

18. Spurious Reactor Trip

At 10:20 p.m. on July 28, 1987, a reactor trip was initiated from IRM Channel No. 17. At the time of the scram, control rod friction testing was in progress with the reactor protection system in a non-coincidental configuration. The hi-hi trip signal was generated by an instrument technician moving some nuclear instrument cables under the reactor vessel causing a noise spike. The NI cabling is sensitive to movement and can create a noise spike if handled. Work under the vessel during periods of non-coincidence RPS alignment is usually avoided to prevent an occurrence similar to this. However, handling was required in this instance to gain access to a Position Indication Probe for replacement. All rods were in the "00" position. The reactor trip signal was reset. No safety implications were noted. The inspector examined charts to verify the time and range of the spike. No abnormal conditions were identified and the inspector had no further questions.

19. Integrated Leak Rate Test (ILRT)

On August 6, 1987, the licensee declared the as-found ILRT a failure due to excessive leakage through Isolation Condenser (IC) valves IC-6 and IC-7. These valves are air-operated condenser vent valves that vent non-condensable gasses to the main steam line. They are normally open during operation and receive an isolation signal to prevent off-site release during an accident. The as-left ILRT was computed to be 0.3395 % weight/day (within the 0.9 % weight/day TS requirement). The root cause of IC-6 and 7 failure was poor post-maintenance valve stroke adjustment. Following valve overhaul, the maintenance technician failed to set valve strokes sufficient to ensure positive seating. This caused excessive seat leakage during the ILRT. The misadjustments were immediately recognized and corrected. The licensee plans to implement a maintenance training program to cover proper post-maintenance valve adjustments. Additionally, performance of Local Leak Rate Testing of post-maintenance valves prior to conducting an ILRT will be investigated. For more detail on this test see Inspection Report 50-245/87-18.

20. Standby Gas Treatment System Actuation

On July 15 the Standby Gas Treatment System (SGTS) automatically actuated on refueling floor high radiation level (approximately 100 mrem/hr). The momentary high radiation signal quickly returned to normal. Area and airborne surveys showed normal radiation levels. The SGTS was subsequently returned to normal standby service. At the time of the actuation the reactor was defueled and Local Power Range Monitor (LPRM) replacements were in progress. The cause of the radiation spike was the short exposure of a portion of an irradiated LPRM above the pool water level during transfer operations. No radiation release occurred. Operators were cautioned to be more careful during LPRM replacement operations. The inspector had no further questions in this area.

21. On-Site Plant Operations Review Committee (PORC)

The resident inspector attended Unit 1 PORC meetings on numerous dates during this inspection period. Technical Specification 6.5.1 requirements for committee composition were met. PORC topics included the following:

-- Review of numerous tests, major and minor routine and non-routine operation, maintenance, surveillance and chemistry procedure changes.

-- Review of numerous Plant Design Change Requests (PDCRs).

-- Review of plant status changes, routine and non-routine events, and special circumstances.

The inspector observed that PORC members exhibited probing and questioning attitudes. They effectively used discussion periods to focus attention on the safety implications of presented items. Active interplay among members supported the PORC chairman in making meaningful and informed decisions. Special presentations made by various staff representatives was an effective method of broadening PORC's understanding of several technical issues. The pace and complexity of events occurring during a refueling outage stress an organization's ability to carefully and safely conduct operations. The PORC is tasked with reviewing these events and plant conditions in order to independently ensure safety of operations. As observed by the inspector, PORC's performance during this period of heightened activity has been excellent. Probing analysis, sound judgement, and conservative evaluation have been evident. The inspector had no further questions in this area.

22. Off-Site Nuclear Review Board (NRB)

The inspector attended a Unit 1 NRB meeting on July 21, 1987. Technical Specification 6.5.3 requirements for board composition were met. The NRB topic for this special meeting was the proposed TS change to allow reactor startup with one of the 20 Jet Pump flow indications out-of-service (see Section 11 for details).

The inspector observed that the NRB performed TS 6.5.3.6 required reviews at a level consistent with the safety significance of this issue. Discussions were consistently perceptive and professional. The inspector had no further questions in this area.

23. Inspection Report 50-245/87-09 Findings

The subject inspection report documents the results of an inspection conducted by members of the NRC's Vendor Inspection Branch on April 20-24, 1987. The findings from this report included three Potential Enforcement Findings (PEFs) and several open items. The licensee has implemented corrective actions on most of these items but is still in the process of completing analyses and documentation packages. The resident inspector has reviewed the licensee's efforts to-date and they appear comprehensive and appropriate. The licensee has responded to concerns of the seismic capabilities of the ADS accumulator's drywell nitrogen supply header by upgrading system supports in order to fully qualify the system. The two PEFs associated with this issue (PEF 50-245/87-09-01 and PEF 50-245/87-09-02) are currently unresolved pending completion of licensee analyses, documentation efforts, and further NRC review for safety significance (UNR 50-245/87-12-02 and UNR 50-245/87-12-03, respectively). PEF 50-245/87-09-06 concerning lack of document control is unresolved pending further NRC review (UNR 50-245/87-12-04). Other open items concerning the IST program remain unresolved pending further regional review (UNR 50-245/87-12-05).

24. Management Meetings

At periodic intervals during this inspection, meetings were held with senior plant management to discuss the findings. No proprietary information was identified as being in the inspection coverage. No written material was provided to the licensee by the inspector.