133(2)

September 20, 1999

Mr. R. P. Necci, Vice President
Nuclear Oversight and Regulatory Affairs
c/o Mr. D. A. Smith, Manager - Regulatory Affairs
Northeast Nuclear Energy Company
P.O. Box 128
Waterford, Connecticut 06385

SUBJECT: NRC COMBINED INSPECTION 50-245/99-08, 50-336/99-08, 50-423/99-08

Dear Mr. Necci:

On August 9, 1999, the NRC completed an inspection at Millstone Units 1, 2, and 3 reactor facilities. The enclosed report presents the results of that inspection.

During the eight-week period covered by this inspection, your staff conducted activities at the Millstone Station with an appropriate focus on safe plant operations. Unit 3 operators performed the reactor and plant startup from the sixth refueling outage in a deliberate and conservative manner. Equipment performance posed few operational challenges to the operators and to the Unit 2 and 3 plants. Our inspection activities at Unit 3 identified acceptable controls and priority for maintenance activities, an appropriate understanding of the risk impacts on the plant, and good coordination among departments. We also understand that Unit 3 management initiated actions to review for potential improvements of those process controls affecting work flow and equipment outage times, and to review the resultant impact upon the operational focus of the plant.

However, our inspectors identified several instances at Unit 2 where your staff failed to initiate condition reports for degraded equipment and take adequate corrective actions. Although we consider the overall corrective action processes to be effective, we are concerned with the number of corrective action issues recently identified by the NRC and the potential for some of these issues to render safety-related systems inoperable. One example was the failure to initiate a condition report and take timely corrective actions in response to evidence that there was air trapped in one train of emergency core cooling system piping. The prompt verification that the line was filled with water was required to ensure that there was no potential to air-bind the associated high pressure safety injection and containment spray pumps. A second example was the failure to initiate a condition report and implement effective corrective actions when a significant amount of water was identified in the oil removed from the outboard bearing of the "B" auxiliary feed water pump during a scheduled oil change on April 12, 1999. Although the bearing oil was replaced at that time, the lack of additional actions resulted in the recurrence of the condition on June 1, 1999. Two other examples where a condition report was not initiated involved excessive reactor building closed cooling water flow to the "B" containment air cooler and a leaking safety injection tank isolation valve.

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Also during this period, we observed your staff performing a comprehensive review and evaluation to understand the cause of a seven rem exposure to an individual's personal radiation monitoring device. Based on available evidence, your staff determined that an actual personnel exposure was not likely. Consequently, your staff is actively investigating the possibility of tampering with the individual's dosimeter.

Based on the results of this inspection, the NRC has determined that four Level IV violations of NRC requirements, which were associated with the above corrective actions issues, occurred. The NRC has also determined that seven Level IV violations of NRC requirements, which were associated with conditions described in Licensee Event Reports (LERs), occurred. Six of the seven LERs concerned issues identified before 1999. These violations are being treated as Non-Cited Violations (NCVs), consistent with the NRC Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violation or severity level of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Millstone facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room (PDR).

Sincerely,

ORIGINAL SIGNED BY:

James C. Linville, Director
Millstone Inspection Directorate
Office of the Regional Administrator
Region I

Docket Nos. 50-245, 50-336 and 50-423

Enclosure: NRC Combined Inspection Report 50-245/99-08, 50-336/99-08 and 50-423/99-08

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U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos.:	50-245	50-336	50-423
Report Nos.:	99-08	99-08	99-08
License Nos.:	DPR-21	DPR-65	NPF-49

Licensee: Northeast Nuclear Energy Company
P. O. Box 128
Waterford, CT 06385

Facility: Millstone Nuclear Power Station, Units 1, 2, and 3

Inspection at: Waterford, CT

Dates: June 15, 1999 - August 9, 1999

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Millstone Inspection Directorate
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Region I

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EXECUTIVE SUMMARY

Millstone Nuclear Power Station
Combined Inspection 50-245/99-08; 50-336/99-08; 50-423/99-08

Operations

- At Unit 2, operators failed to initiate a condition report and take timely corrective actions when they suspected that the piping between the "B" train containment sump isolation valve and the downstream check valve was not full of water. Trapped air in the piping had the potential to render the "B" train high pressure safety injection (HPSI) and containment spray pumps inoperable. However, operators inappropriately determined that it was acceptable to wait up to four weeks to determine whether the piping contained air. Prompt actions, including the confirmation of trapped air in the containment sump suction piping, were not taken until concerns were raised by the NRC inspector about three weeks later. Although the amount of trapped air was small and would not have prevented the "B" HPSI and containment spray pumps from performing the intended function, the failure to address this deficient condition in a timely manner is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-01) (Section U2.O1.2)

- Prior to Unit 2 plant startup, the licensee failed to initiate a condition report when a five-day trend showed the No. 3 safety injection tank (SIT) was leaking by the closed isolation valve to the reactor coolant system (RCS). A condition report was necessary to initiate an assessment of SIT operability with the leaking isolation valve. Following an NRC inquiry, a condition report was initiated and the licensee's operability determination found the SIT to be operable. The NRC found that the operability determination was adequately supported and an acceptable corrective action plan was developed. The failure to initiate a condition report is a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instruction, Procedures and Drawings." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-02) (Section U2.O1.3)

- Overall Unit 3 plant operations and specific operational evolutions were well controlled during this inspection period. While the plant challenges requiring the unplanned entry into a technical specification action statements were few, the plant operators and management responded to these events in a deliberate, yet timely, and conservative manner. (Section U3.O1.1)

Maintenance

- In August 1997, the Unit 2 "A" emergency diesel generator (EDG) inadvertently started during troubleshooting activities. The root cause of the event was a failure to establish enough detail in a maintenance troubleshooting procedure to prevent an inadvertent EDG start. The licensee's corrective actions included establishing adequate procedural controls over troubleshooting activities on safety-related equipment. The root cause evaluation was thorough, and the immediate and long term corrective actions were adequate. The failure to establish and implement adequate procedures in accordance

with Technical Specification 6.8.1 is a violation of NRC requirements. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV 50-336/99-08-03). Licensee Event Report 50-336/97-027-00 is closed. (Section U2.M8.1)

- At Unit 2, the licensee identified in 1997 that they failed to meet certain portions of ASME Section XI surveillance requirements, as required by Unit 2 Technical Specifications (TS). The licensee's corrective actions included procedural changes, implementation of additional testing, and gaining approval to use specific code cases. The licensee properly reported, and corrected the deficiency. The root cause evaluation was thorough, and the immediate and long term corrective actions were adequate. The failure to meet the ASME Section XI testing requirements, as required by Unit 2 TS, is a violation of NRC requirements. This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-04) Licensee Event Report 50-336/97-024-00 &-01 is closed. (Section U2.M8.3)

- At Unit 2, the licensee identified and reported that a technical specification (TS) required fire protection related surveillance of a specific roll-up fire door had not been routinely performed. The fire loading on either side of the door was determined to be low and tested doors on either side of the untested door provided adequate protection from the spread of fire. The licensee adequately identified, reported, and corrected this deficiency. The failure to perform this technical specification required surveillance is considered a minor violation and is not subject to formal enforcement action. Licensee Event Report 50-336/99-001-00 is closed. (Section U2.M8.5)

- Overall, the inspection of selected Unit 3 maintenance activities, including field observations, document reviews, and work controls and priorities, identified acceptable practices and good coordination across the unit departments. The prioritization and authorization for off-shift work hours to complete safety-related and risk significant equipment work, and repair activities requiring entry into a technical specification action statement were well controlled. Good coordination of the daily work to minimize plant risk was evident. Preventive maintenance inspections and other work were well planned and procedurally controlled. In the case of reviewed service water system activities, the system engineer appropriately implemented an operating strategy for monitoring and trending equipment conditions. (Section U3.M1.1)

- Observed Unit 3 surveillance activities were generally performed in a controlled manner in accordance with approved procedures. One instance of inattention to detail was observed by the inspector regarding improper independent verification. The error was corrected and did not recur through the rest of the surveillance. (Section U3.M1.2)

- The maintenance rule was properly implemented on the Unit 3 risk significant service water, auxiliary feedwater, and containment recirculation spray systems. Scoping information, performance criteria and unreliability data were maintained in accordance with approved procedures. Maintenance rule action plans were in place for the applicable systems and their status and system unavailability were monitored by licensee management. (Section U3.M1.3)

- The licensee had failed to verify that each Unit 3 diesel started from standby conditions since May of 1995, and this is considered a violation of NRC requirements. Based upon the licensee's promptly initiated corrective actions upon problem discovery, this Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-423/99-08-11) LER 50-423/99-003-00 is closed. (Section U3.M8.1)

- The failure to complete the noble gas grab sample within the required time is a violation of NRC requirements. The safety significance of this Unit 3 technical specification violation is minimal due to the relative short time period involved and since the main stack continued to be monitored. The failure to perform this technical specification required surveillance is considered a minor violation and is not subject to formal enforcement action. LER 50-423/98-18-00 is closed. (Section U3.M8.2)

Engineering

- At Unit 2, the licensee failed to initiate a condition report and implement effective corrective actions when a significant amount of water was identified in the oil removed from the outboard bearing of the "B" auxiliary feed water pump during a scheduled oil change on April 12, 1999. As a result, the condition recurred during continuous operation of the pump from May 25 through 29, 1999, and the degraded condition was not identified and corrected until June 1, 1999. In addition, the licensee's assessment of operability during the period prior to June 1, 1999, was not well founded in that it was based on the ability of the system, rather than the component, to perform its design function. Finally, the licensee inappropriately used the conclusion that the pump had been operable as a basis to reduce the degree of thoroughness in identifying and implementing corrective actions to address the recurrent problems with water intrusion. The failure of the licensee to implement adequate corrective actions to address the water intrusion problems on April 12, 1999, is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-05) (Section U2.E1.1)

- At Unit 2, following the repair of a reactor building closed cooling water (RBCCW) throttle valve, the licensee failed to initiate a condition report when RBCCW flow to the "B" containment air recirculation cooler significantly exceeded the post-maintenance acceptance criteria. Because this higher flow rate could have resulted in insufficient RBCCW flow to other safety-related components, a condition report was necessary to initiate an operability assessment of the "B" RBCCW train, which was in service. Although a subsequent evaluation showed that the RBCCW flow to other safety-related components would have remained within established margins, the failure to initiate a condition report, as required by the licensee's administrative procedure governing their corrective action program, is a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-06) In addition, rather than using an approved procedure, an engineering disposition was inappropriately used to provide instructions to manipulate the in-service RBCCW system to establish a new throttle position for the repaired valve. (Section U2.E1.2)

- At Unit 2, the licensee identified in 1997 that a failed, non-quality assurance (non-QA) lamp was installed in a QA circuit and had to the potential to affect the performance of safety-related circuits. The failure of the licensee to implement appropriate quality standards and measures for the selection and review of suitability of application of material, parts, equipment, and processes that are essential to the safety-related functions of systems and components is a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-07) Licensee Event Report 50-336/97-021-00 is closed. (Section U2.E8.2)

- At Unit 2, the licensee identified in 1997 that a postulated single failure of a condenser hotwell makeup valve would cause a diversion of water from the condensate storage tank and impact the availability of sufficient water for the auxiliary feedwater system to perform its safety function. The licensee adequately determined the root cause of the single failure vulnerability and took appropriate corrective actions. The failure to establish appropriate design controls to ensure that safety-related equipment would function as assumed in the Unit 2 Final Safety Analysis Report is a violation of 10 CFR 50, Appendix B, Criteria III, "Design Control." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-08) Licensee Event Report 50-336/97-025-00 is closed. (Section U2.E8.3)

- At Unit 2, the licensee identified in 1998 that, under some postulated high energy line break or seismic design basis accident conditions, the isolation of 120 volt vital AC electrical faults could not be ensured. The licensee appropriately reported and corrected the deficiency. The root cause evaluation was thorough, and the corrective actions were adequate. The failure to ensure that safety-related 120 volt vital AC equipment was designed in accordance with 10 CFR 50, Appendix B, Criterion III, "Design Control," to adequately respond to design basis accidents, is a violation of NRC requirements. This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-09) Licensee Event Report 50-336/93-001-00 is closed. (Section U2.E8.4)

- At Unit 2, the licensee identified in 1998 that inadequate calculations of limiting power distributions had been performed for the Main Steam Line Break Analysis for cycle 13. As part of the corrective action, the licensee adequately reported the deficiency, requested a technical specification change and received a license amendment to resolve the deficiency. The failure to perform an adequate main steam line break analysis is a violation of 10 CFR 50 Appendix B, Criterion III, "Design Control." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-10) Licensee Event Report 50-336/98-007-00 &-01 is closed. (Section U2.E8.5)

- The review of ongoing Unit 3 engineering activities, conducted as follow-up to known system or equipment problems, revealed adequate design implementation, within the assumed accident analysis and other design-basis considerations. Where commitments had been made by the licensee to address specific design concerns (e.g., component environmental qualification for steam line breaks; piping configuration analyses to review gas accumulation; high energy line break assumptions), the inspector verified that the

licensee implemented the appropriate actions to further evaluate the identified issues. (Section U3.E1.1)

Plant Support

- The licensee is continuing to conduct an aggressive and comprehensive event review of a 7.04 rem exposure, involving an individual's personnel thermoluminescent dosimeter (TLD), to determine if the exposure represents an actual exposure to an individual or was the result of tampering with the individual's TLD. The licensee's event review effort was conducted by knowledgeable personnel, and was comprehensive in scope and depth. (Section R1.1)

- There has been an increase in the turnover rate in the security force sergeant ranks causing a shortage of sergeants to man required posts. The inspection determined that all required posts have been properly manned, overtime being worked by the sergeants was within prescribed guidelines and management was taking action to train and qualify additional sergeants to increase staffing levels. (Section S6)

- The fitness-for-duty programs was being implemented in accordance with the licensee's procedures and regulatory requirements. (Section S8)

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Report Details

Summary of Unit 1 Status

The licensee selected Entergy Nuclear to provide management services for the decommissioning of Millstone Unit 1, effective June 1, 1999. Since that time, Entergy Nuclear has established an organizational structure with appropriate reporting responsibilities to the licensee's organization, with the licensee retaining ultimate responsibility for compliance with the NRC license for the unit. In addition, on June 23, 1999, the licensee submitted to the NRC the Post Shutdown Decommissioning Activities Report, as required by 10 CFR 50.82(a)(4)(i). Overall, licensee activities have been conducted in a safe and deliberate manner, with no safety issues identified to date. Activities that are currently being planned, include: (1) the transfer of unirradiated fuel assemblies (new fuel) from the spent fuel pool (SFP) to the appropriate in-plant storage facilities, (2) cleanup of the SFP, which is a licensee regulatory commitment to the NRC, (3) design basis reclassification of Unit 1 systems from an operational perspective to the current decommissioning state, and (4) the programmatic and physical separation of Unit 1 from the site protected area such that operational impact on the remaining two units is adequately addressed.

The inspector also reviewed current NRC open items at Unit 1, and identified several items that can be administratively closed due to one or more of the following reasons: (1) The licensee had certified in July of 1998, in accordance with 10 CFR 50.82(a)(1)(i) and (ii), that they had permanently ceased operations and that fuel had been permanently removed from the reactor vessel, (2) The fundamental performance issues related to the violations (VIO), unresolved items (URI), and escalated enforcement items (EEI) listed below were similar or common to the performance issues dispositioned by the NRC in both the Exercise Of Enforcement Discretion, dated April 16, 1998, and the Notice of Violation and Proposed Imposition of Civil Penalties dated December 10, 1997, (3) The NRC issued a Notice of Violation and Exercise of Enforcement Discretion, by letter to the licensee dated May 25, 1999, which was related to activities regarding the Unit 1 SFP, and (4) The NRC issued a Final Director's Decision Pursuant to 10 CFR 2.206, dated July 27, 1999, which was related to SFP activities at Unit 1.

VIO 01012/EEI 95-82-04	VIO 01022/EEI 95-82-14	VIO 01032/EEI 95-82-10,11,18
VIO 01182/EEI 95-82-09	VIO 04013/EEI 95-82-12	EEI 95-82-03
EEI 95-82-08	URI 95-82-13	EEI 95-82-19
EEI 95-82-20	URI 95-82-02	

Report Details

Summary of Unit 2 Status

Unit 2 entered the inspection period in Operational Mode 1, power operation, with the plant at 100 percent power. Operators conducted a brief planned power reduction to 80 percent power on July 10, 1999, for turbine control valve testing. Operators reduced power to 90 percent on the following two other occasions for corrective maintenance affecting the "C" condensate pump: July 30 through July 31, 1999, and August 7, 1999. At the conclusion of the inspection period, the plant remained in operation at 100 percent power.

U2.I Operations

U2 O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspector conducted frequent reviews of ongoing plant operations, including observations of operator evolutions in the control room; walkdowns of the main control boards; tours of the Unit 2 radiologically controlled area and other buildings housing safety-related equipment; and observations of several management planning meetings.

The inspector observed procedural adherence and conformance with technical specification requirements during routine operation at power, including periods where surveillance testing and maintenance activities were ongoing. Among operators in the control room, the inspectors noted good communication practices. However, the inspectors noted inadequate sensitivity of operators to degraded plant conditions potentially affecting the operability of safety-related systems and components. Examples of this weakness are described in the following two sections as well as, Sections U2.E1.1 and U2.E1.2 of this report.

O1.2 Air Trapped in the "B" Emergency Core Cooling System

a. Inspection Scope (71707)

On June 29, 1999, the inspector observed a note in the Unit 2 Shift Turnover Report to record if water is discharged from a vent during the next performance of procedure SP 2604G/H, "Containment Sump and Shutdown Cooling Heat Exchanger Outlet Valve Operability Tests." Subsequently, the inspector found out that the reason for this planned action was the licensee's suspicion that air may have been trapped in the containment sump supply piping between valves 2-CS-16.1A/B, the containment sump header isolation valves, and valves 2-CS-15A/B, the containment sump supply header check valves. The inspector reviewed and evaluated the licensee's actions to address the issue of potential air entrapment.

b. Observations and Findings

On June 8, 1999, the Unit Supervisor was evaluating the need to continue training plant equipment operators (PEOs) to fill the containment sump suction line upstream of valves 2-CS-16.1A/B. The periodic filling of the piping had been performed to prevent the potential pressure locking of valves 2-CS-16.1A/B by thermally isolating the valve from the containment atmosphere. However, this evolution was no longer considered necessary and had not been recently performed, because a modification completed in early 1999 prevented potential pressure locking of these valves. During his evaluation, the Unit Supervisor noted that during the last performance of test procedure SP 2604H, which cycled valve 2-CS-16.1B, the PEOs did not recall observing water discharge from the then open vent valve in the piping between valve 2-CS-16.1B and valve 2-CS-15B, which suggested the piping segment was not filled with water. During the parallel testing of the "A" train, the PEOs had observed water discharge from the vent valve due to back leakage through check valve 2-CS-15A, which kept the "A" train piping filled with water. This discrepancy between tests prompted the Unit Supervisor to ask Engineering if the observed condition was acceptable.

On June 10, 1999, Engineering responded to Operations question, stating that the piping segment should be verified to be full. After further questioning by Operations, Engineering stated that if the lines were not full, the air trapped in the piping may collect in and potentially air bind the high pressure safety injection (HPSI) and containment spray (CS) pumps, if the systems were called upon to function during a postulated accident. The inspector considered that this information should have raised questions on the operability of the pumps.

On June 16, 1999, Operations determined that it was acceptable to wait up to four weeks for the next performance of test procedure SP 2604G/H to ascertain whether the leak rate through valves 2-CS-15A/B was sufficient to keep the piping full. The reason they found it acceptable to wait up to four weeks was that they believed that the operability of the emergency core cooling system (ECCS) flow path and pumps was not in question. The Unit Supervisor added a note to the Unit 2 Shift Turnover Report to ensure that observations during the next performance of the test procedure would be documented.

On June 29, 1999, the inspector discussed the note in the Unit 2 Shift Turnover Report with the Unit Supervisor. Because the PEOs who performed procedure SP 2604G/H recalled that only check valve 2-CS-15A leaked enough to cause water to discharge from the "A" train containment suction piping vent, the inspector questioned the basis for the operator's belief that the operability of the "B" train ECCS flow path and pumps would not be affected by potential air entrapment. The inspector also questioned the basis for not generating a condition report to document the potential for trapped air in the piping between valves 2-CS-16.1B and 2-CS-15B.

In response to the inspector's questions, the licensee generated condition report (CR) M2-99-1955 describing the concern and immediately performed procedure SP 2604G/H to ascertain the amount of leakage through check valves 2-CS-15A/B. The leakage through check valve 2-CS-15A was found to be sufficient to keep the containment sump

piping full. Based on that finding, the licensee concluded that the "A" train of the ECCS remained operable and prepared Operability Determination MP2-030-99 to document that conclusion. However, when the vent valve on the "B" train ECCS header was opened for 30 seconds, air was heard escaping for about five seconds then nothing came out. This confirmed that the piping between valves 2-CS-16.1B and 2-CS-15B was not filled. As a result, the licensee declared the "B" train ECCS, the "B" HPSI pump, and the "B" CS pump inoperable and entered a 48 hour technical specification action statement. The piping between valves 2-CS-16.1B and 2-CS-15B was subsequently filled and the 48 hour technical specification action statement was exited approximately 27 hours after entry.

On July 8, 1999, the licensee completed a reportability determination for the air void in the "B" train ECCS and determined that the condition was not reportable. When the containment sump piping was filled on June 30, 1999, the licensee recorded the level changes in the refueling water storage tank and the containment sump. Using these values, the licensee calculated that 0.5 cubic feet of air had been trapped in the piping between 2-CS-16.1B and 2-CS-15B. Based on the piping configuration and flow considerations, the licensee determined that 0.5 cubic feet of air would have minimal impact on the long term operation of the "B" train HPSI and CS pumps and, therefore, determined that the condition was not reportable.

The inspector reviewed the licensee's reportability determination and agreed that 0.5 cubic feet of entrapped air would not have prevented the HPSI and CS pumps from performing their design function. However, the licensee believed that if there was no water in the 6.8 feet of piping between valves 2-CS-16.1B and 2-CS-15B, the 21.4 cubic feet of trapped air would have rendered the HPSI and containment spray pumps inoperable.

c. Conclusion

Operators failed to initiate a condition report and take timely corrective actions when they suspected that the piping between the "B" train containment sump isolation valve and the downstream check valve was not full of water. Trapped air in the piping had the potential to render the "B" train HPSI and CS pumps inoperable. However, operators inappropriately determined that it was acceptable to wait up to four weeks to determine whether the piping contained air. Prompt actions, including the confirmation of trapped air in the containment sump suction piping, were not taken until concerns were raised by the NRC inspector about three weeks later. Although the amount of trapped air was small and would not have prevented the "B" HPSI and containment spray pumps from performing their intended function, the failure to address this deficient condition in a timely manner is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-08-01)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the licensee entering the issue into their corrective action program (Condition Report M2-99-1955).

O1.3 Safety Injection Tank Outlet Isolation Valve Leakage

a. Inspection Scope (71707/37551)

The inspector evaluated the licensee's actions to address leakage from the No. 3 safety injection tank (SIT) outlet isolation valve.

b. Observations and Findings

During a routine control room tour on April 12, 1999, with the plant in Operational Mode 5, "Cold Shutdown", the inspector observed that the level in the No. 3 safety injection tank (SIT) was low and the associated annunciator was lit. The control room operators had been monitoring the level decrease for several days, and they determined the leakage was through the SIT outlet isolation valve, valve 2-SI-634, to the reactor coolant system (RCS). Since depressurizing the reactor coolant system below SIT pressure on April 7, 1999, the No. 3 SIT had lost about 20 percent of its initial water inventory.

The SITs are designed to use pressurized nitrogen at about 225 psig to inject borated water to the reactor coolant system following a rapid depressurization. The SIT outlet isolation valves are designed to remain open when the plant is pressurized to provide automatic injection of water to recover from postulated large loss-of-coolant accidents. However, in 1998, the licensee determined that, for certain small loss-of-coolant accidents, SIT injection must be blocked to prevent the nitrogen that follows the injection from interfering with steam generator decay heat removal. Injection may be blocked by closing the SIT outlet isolation valve or opening the nitrogen vent valve. Two methods were necessary to satisfy the single failure criterion for long-term decay heat removal.

The licensee had previously identified leakage through the No. 3 SIT outlet isolation valve on January 27, 1999. To stop the leakage, operators manually closed the valve using the local handwheel. Based on the number of handwheel turns necessary to completely close the valve, the licensee concluded that the remote switch, which returns to a position that stops valve motion when released, had not been held in the closed position for an adequate length of time to close the valve. The licensee developed operator aides to remind operators of the need to hold the switch in the desired position for the necessary length of time.

The inspector evaluated the actions taken by the licensee to address the leakage through valve 2-SI-634 considering the safety function of the valve and previous leakage from this valve observed on January 27, 1999. The inspector discussed the leakage from the No. 3 SIT with the control room operators and determined that, although the leakage was being monitored over several days, neither a condition report (CR) nor trouble report had been initiated to resolve the condition. Discussions with the responsible system engineer and the responsible motor-operated valve engineer later that day indicated that other work groups were unaware of the condition. Subsequently, the control room operators documented the condition in CR M2-99-1324.

Prior to plant restart, the licensee completed an operability determination that found that the No. 3 SIT outlet isolation valve was operable but not fully qualified. This determination assumed a leak rate higher than the observed leak rate to provide margin because the repeatability of the valve position was not known. At the higher than observed leak rate, the licensee determined that nitrogen intrusion would begin several days after the initiating event and would occur at a slow rate. Under these conditions, the licensee concluded that the operators would be able to dissipate the nitrogen that entered the RCS using the reactor vessel head vents or would be capable of restoring power to the SIT vent valve to vent the nitrogen directly to containment. The inspector found this operability determination acceptable.

The inspector reviewed the licensee's reporting requirements for conditions adverse to quality. Administrative procedure RP4, "Corrective Action Program," requires plant personnel to initiate condition reports for conditions that have a potential or actual adverse effect on plant safety. The inspector found that the failure to initiate a condition report following the failure of the post-maintenance test, as required by administrative procedure RP4, was a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instruction, Procedure, and Drawing."

Because of the repetitive nature of the No. 3 SIT isolation valve leakage, the inspector reviewed the licensee's corrective action plan for this issue. The licensee reviewed information regarding the number of turns of the manual valve operator for valve 2-SI-634 to stop leakage in the two instances, and traces of closing and opening force for all four of the SIT isolation valves. The licensee found that significantly fewer turns of the manual handwheel were required to close the valve in the second instance than in the first, and that the opening force of the No. 3 SIT isolation valve was significantly lower than the opening force of the other three SIT isolation valves. Based on this information, the licensee concluded that the leakage in the second instance resulted from an inadequate closing torque switch setpoint for this particular valve's disc-to-seat interface. The licensee plans to adjust the torque switch setpoint and retest the valve during the next refueling outage. The inspector found the licensee's corrective action plan acceptable.

c. Conclusions

Prior to Unit 2 plant startup, the licensee failed to initiate a condition report when a five-day trend showed the No. 3 SIT was leaking by the closed isolation valve to the RCS. A condition report was necessary to initiate an assessment of SIT operability with the leaking isolation valve. Following an NRC inquiry, a condition report was initiated and the licensee's operability determination found the SIT to be operable but not fully qualified. The NRC found that the operability determination was adequately supported and an acceptable corrective action plan was developed. The failure to initiate a condition report, as required by the licensee's administrative procedure governing their corrective action program, is a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-08-02)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations

based on the licensee entering the issue into the corrective action program. This violation is in the licensee's corrective action program as Condition Report M2-99-1324.

U2 O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) URI 50-245, 336, 423/97-85-02: Training Program Deficiencies - CAL Item 8
Unresolved Item (URI) 50-245, 336, 423/97-85-02 is being administratively closed, because the outstanding concerns associated with the item are being tracked by URI 50-245, 336, 423/97-01-03. URI 50-245, 336, 423/97-85-02 was opened to evaluate identified training program deficiencies as they related to inaccurate information that was provided in several Personal Qualification Statements (Form 398s) that were submitted to the NRC staff as an application for an operator's license. These training program deficiencies were reviewed in NRC Inspection Report 50-336, 423/99-02 and were found to be acceptably addressed to support closure of NRC Confirmatory Action Letter (CAL) 1-97-010, dated March 7, 1997. Although the NRC found that the licensee had implemented sufficient measures to ensure the accuracy of future Form 398s, NRC review of the historical aspects of this concern is ongoing. Because this ongoing review is already being tracked by URI 50-245, 336, 423/97-01-03, URI 50-245, 336, 423/97-85-02 is administratively **closed**. As part of the review of URI 50-245, 336, 423/97-01-03, the NRC will evaluate whether a violation of NRC requirements occurred.

O8.2 (Closed) URI 50-245, 336, 423/97-85-03: Establish Training Staff Prior Staff Levels

a. Inspection Scope (90712, 92700, 92703)

The inspector performed in-office and on-site document reviews of the licensee's actions to address unresolved item (URI) 50-245, 336, 423/97-85-03. This URI was written to review the licensee's corrective actions for Condition Report (CR) M1-97-2104, issued September 15, 1997, which concluded that training resources were inadequate to support Millstone Unit 1 licensed operator requalification training (LORT) cycle 97-5 and to develop LORT cycle 97-6 training. In addition, the URI was written to evaluate the potential impact of the Unit 1 training resource problems on the other units and/or the possibility of similar problems on Units 2 and 3.

b. Observations and Findings

The CR was initiated by the Unit 1 LORT program coordinator noting a number of management and support problems in the Unit 1 LORT program. The NRC reviewed the CR and associated corrective actions in NRC Inspection Report (IR) 50-245, 336, 423/97-85. NRC IR 50-245, 336, 423/97-85 states that the inspectors were unable to review the extent of LORT weaknesses on Units 2 and 3 training staffs or to determine whether Unit 2 or Unit 3 training had been affected. The report further states that inspections of Unit 2 and Unit 3 requalification annual operating tests and a July 1997 Unit 3 NRC license examination did not provide evidence of adverse training resource impacts.

During this inspection, the inspector reviewed NRC Confirmatory Action Letter (CAL) 1-97-010, issued on March 7, 1997, in response to a March 3, 1997, letter from NU which transmitted an Independent Review Team (IRT) report concerning Millstone 1 licensed operator examination failures. Various NRC inspection reports addressed the IRT report, the corrective action plan, the licensee's submittals in response to CAL items, and facility actions addressing deficiencies regarding all three Millstone units. NRC IR 50-336, 423/97-85 closed CAL items 4, 5 and 6 and NRC IR 50-336, 423/99-02 closed remaining CAL items 1, 2, 3, 7, 8, and 9. Therefore, the licensee's technical and organizational corrective actions and response to the CAL were adequate.

The inspector also reviewed the current Licensed Operator Requalification Training Program Description (TPD-7.080), Unit 2 licensed operator shift manning levels and the current Unit 2 licensed operator training schedule that is being implemented. The inspector found that the licensee is presently implementing the program and schedule that was inspected by the NRC and found to be adequate to close the CAL item. Licensed operator shift manning on Unit 2 was determined to meet Unit 2 technical specifications. Inspection Report 50-336/99-04, Operational Safety Team Inspection, found that operator knowledge, training, qualification, and performance were adequate and that the operators were supported by an adequately staffed operations organization. Resource loading and manning impacts of the type associated with this URI were not identified by the NRC in the Unit 2 LORT program.

c. Conclusion

A review of an unresolved item related to the Unit 2 LORT was conducted. Because of the program and technical closures in NRC IRs 50-336, 423/97-85; 50-336, 423/99-02; and, 50-336/99-03; the existence of URI 50-245, 336, 423/97-01-03, to address the historical aspects of the Millstone LORT problems; and the absence of apparent Unit 2 programmatic LORT problems as documented in this report and NRC IR 50-336/99-04; URI 50-245, 336, 423/97-85-02 is administratively **closed**. As part of the review of URI 50-245, 336, 423/97-01-03, the NRC will evaluate whether a violation of NRC requirements occurred.

O8.3 (Closed) VIO 50-336/98-207-06: Failure to Implement Written Procedures for Operation of the Reactor Building Closed Cooling Water (RBCCW) System

a. Inspection Scope (90712, 92700, 92903)

In-office, in-field and on-site document reviews were conducted of the licensee's violation response and corrective actions (including those documented in Condition Report M2-97-1871), associated with a September 2, 1997, Unit 2 configuration control event.

b. Observations and Findings

The inspector reviewed the fill and vent operation that was performed on the "A" train RBCCW header on September 2, 1997. During this evolution, clearance tags associated with the "C" RBCCW heat exchanger Unit 2 outlet isolation valve (2-RB-4.1E) were

cleared without an individual clearance being developed for an open automated work order (AWO) M2-97-207. An individual clearance was required because a retest for AWO M2-97-207 had not been performed to establish operability of the actuator for valve 2-RB-4.1E. Valve 2-RB-4.1E performed the function of separating the Unit 2 RBCCW header from the non-operational RBCCW header being drained. Following removal of the clearance tags, local position verification and restoration of valve 2-RB-4.1E, the valve began to open as a result of a miswired actuator solenoid. The valve opening caused a diversion of Unit 2 RBCCW inventory to the "A" train header, resulting in reduced "B" train RBCCW header pressure, the trip of the "C" RBCCW pump on a protective low suction pressure, and entry into an abnormal operating procedure.

The inspector reviewed the licensee's corrective actions associated with the violation, Condition Report M2-98-1413, the licensee's updated root cause analysis, an operations training/briefing record (98-07-07-02), an operator training plan, and Action Requests 97021773-04, 97021773-05 and 97019966-04. In addition, the event was discussed with two control room operators. Finally, a sample of existing clearance tagouts was reviewed for similar problems. The licensee's corrective actions were adequate.

Section M8.1 of NRC Inspection Report (IR) 50-336/98-207-06 discussed one salient aspect of the event about which the licensee was asked to comment in response to the violation. The licensee was asked to address the concern that a previous version of procedure WC 10, "Temporary Modifications," did not provide instructions on the transfer of lifted lead markings from an original component to a replacement component. This standard is established by ANSI 18.7-1976, to which the licensee is committed. The licensee's response to the violation (B17350) did not specifically address this request. However, the inspector verified that procedure WC 10, revision 2, dated 12/14/98 includes a requirement, in step 1.13.5, for the independent and dual verification of lifted leads.

Unresolved Item 50-336/97-207-03 was established to review the licensee's root cause analysis of the September 2, 1997, RBCCW System Event, and was closed in NRC IR 50-336/98-207. The licensee's final root cause analysis was also reviewed in this inspection report to ensure that the weaknesses identified and discussed in NRC IR 50-336/98-207 were resolved. The licensee's overall root cause was previously found to be incomplete in that no root cause was identified for a loss of system function resulting from a detectable maintenance error. The inspector found that the current root cause associated with Condition Report M2-98-1413 addressed this weakness identified in NRC IR 50-336/98-207 and was adequate. No violation of NRC requirements associated with this URI was identified.

c. Conclusion

On September 2, 1997, Unit 2 entered an abnormal operating procedure because a fill and vent operation that was being performed on the Unit 1 Reactor Building Closed Cooling Water (RBCCW) header caused a diversion of Unit 2 RBCCW inventory to the Unit 1 header, resulting in reduced Unit 2 RBCCW header pressure and the trip of the "C" RBCCW pump on a protective low suction pressure. Violation 50-336/98-207-06

was issued to document a failure to adequately implement written RBCCW operating procedures. The licensee's corrective actions in response to the event and the violation were adequate. Violation 50-336/98-207-06 is **closed**.

O8.4 (Closed) VIO 50-336/98-216-01; Mispositioning of a Throttle Valve in the Reactor Building Closed Cooling Water System

a. Inspection Scope (92901)

The inspector reviewed the licensee's corrective actions associated with violation (VIO) 50-336/98-216-01, involving an inadequate surveillance procedure to verify that throttle valves are in their correct position that resulted in the undetected mispositioning of a remotely-operated throttle valve in the reactor building closed cooling water (RBCCW) system.

b. Observations and Findings

The licensee performed a thorough root cause investigation in response to the cited violation and developed appropriate corrective actions. The licensee implemented corrective actions that directly address the violation, including the following actions:

(1) changing the RBCCW system surveillance procedures to require local verification of throttle valve position for remotely operated RBCCW system valves used as throttle valves;

(2) reviewing other safety-related systems for remotely operated valves used as throttle valves to ensure their position was appropriately controlled;

(3) changing the RBCCW operating procedure to provide information on the operational effects of manual operation of remotely operated valves used as throttle valves;

(4) changing the station procedure regarding configuration control to specify that special procedures restore affected systems to their normal alignment using approved procedures;

(5) improving operator guidance for tracking of abnormal system alignments.

In addition, the licensee conducted briefs for operators to improve sensitivity to over-ranged indications to address the inadequate response of operators to the high flow condition resulting from mispositioned RBCCW system throttle valves. The inspector found these corrective actions acceptable.

c. Conclusions

The licensee implemented adequate corrective actions to address the failures associated with Violation 50-336/98-216-01. Therefore, Violation 50-336/98-216-01 is **closed**.

U2.II Maintenance

U2 M1 Conduct of Maintenance

M1.1 Replacement of Packing on the "B" Auxiliary Feedwater Pump

a. Inspection Scope (62707)

The inspectors observed a portion of the work activities associated with automated work order (AWO) M2-99-07589, "Packing Replacement on Outboard End of "B" Auxiliary Feedwater (AFW) Pump." The inspector reviewed the work order and associated documents and interviewed licensee field personnel to evaluate the maintenance activities and the functionality of the "B" AFW pump with respect to technical specifications and other requirements.

b. Observations and Findings

The inspector observed a portion of the reassembly of the AFW pump packing gland. The inspector discussed the process for reassembly of the pump packing gland with the mechanics. The inspector found that the work was being performed in accordance with approved procedures and that the work order was present at the work site. A review of the work package found that it was complete with respect to work authorization, an approved procedure, and post-maintenance test requirements.

During the discussion involving the packing gland reassembly, one of the mechanics explained that the as-found alignment of the packing rings had displaced the lantern ring from its optimum position. The packing gland area is an annular space between the pump shaft, which rotates during pump operation, and the pump casing. The lantern ring is a device that enhances uniform water flow around the packing rings for cooling. For optimum performance, the lantern ring must be aligned with the port that provides cooling water to the packing gland area. The mechanic stated that the as-found packing configuration had too many packing rings installed between the back of the packing gland and the lantern ring, which caused the cooling water port to be partially blocked. With the cooling water port partially blocked, the packing compression must be reduced to provide adequate cooling water flow for the packing. When the packing was replaced, the mechanic used fewer packing rings between the back of the packing gland and the lantern ring.

The inspector evaluated the basis for relocating the lantern ring because of the potential relationship of between packing water leakage and the bearing water intrusion discussed in Section U2.E1.1 of this report. One of the mechanics produced a drawing of packing gland dimensions measured during the packing replacement following overhaul of the "A" AFW pump, which had been performed several months earlier. The mechanic measured the same dimensions on the "B" AFW pump and used the measurements to determine the correct number of packing rings for optimum lantern ring placement. The mechanic noted that the packing configuration used in the pump differed from a diagram included in maintenance procedure MP2703A10, "Motor Driven Auxiliary Feed Pump

Overhaul," and initiated Condition Report (CR) M2-99-2015 to document the discrepancy. The procedure did not provide specific directions regarding packing configuration, nor did the procedure refer the mechanic to the diagram for packing installation.

The inspector discussed the control of the packing configuration with the mechanical maintenance manager and the responsible maintenance engineer. The licensee did not classify the packing as safety-related, because it performed only the housekeeping function of reducing pump shaft leakage and because packing installation was considered within the skill of the mechanics. Therefore, specific control of the packing configuration is not required. Nevertheless, the licensee stated that the procedure would be enhanced to provide additional instructions on packing configuration. In addition, the maintenance personnel stated that they had contacted the pump vendor and determined that the vendor considered either the as found or the replacement packing configuration acceptable, because either arrangement placed the lantern ring with some overlap with the cooling water port. The inspector agreed with the licensee's packing classification and found the licensee's actions appropriate.

c. Conclusions

The inspectors concluded that the packing replacement on the "B" AFW pump was performed well and complied with applicable regulatory requirements. The mechanics used the appropriate procedures and completed the work as outlined in the work packages. The mechanics initiated appropriate corrective actions to improve the procedural direction for the work activity.

U2 M8 Miscellaneous Maintenance Issues

M8.1 (Closed) LER 50-336/97-027-00: Unplanned Automatic Start of the "A" Emergency Diesel Generator (EDG) While Troubleshooting

a. Inspection Scope (90712, 92700, 61726)

The inspector reviewed the licensee's corrective actions in response to an unplanned automatic start of the "A" EDG that was reported Licensee Event Report 50-336/97-027-00.

b. Observations and Findings

The inspector performed in-office, in-field and on-site record reviews of a reported event that resulted during maintenance related trouble shooting. LER 50-336/97-027-00; Condition Report (CR) M2-97-1535; Unit 2 Drawing 25203-39047 sheet 11; Procedure OP2384, "ESAS Operation"; Procedure WC 1, "Unit 2 Work Control Process," revision 1; and the licensee's condition report data base were reviewed. The licensee determined that the root cause of the event was a failure to establish enough detail in the troubleshooting procedure used on the "A" EDG. The licensee's corrective actions included establishing improved controls over troubleshooting activities on safety-related

equipment. The corrective actions were adequate, and there was no indication of an adverse trend in the CR data base concerning troubleshooting activities.

The inspector found that the licensee appropriately reported, and corrected the deficiency. The root cause evaluation was thorough, and the immediate and long term corrective actions were adequate. The inspector determined that the maintenance procedure (troubleshooting plan) used during this activity was not prepared to the standard used for other station safety related procedures and did not receive an independent technical review. This resulted in the procedure prescribing a set of EDG starting circuit relay contact alignments that inadvertently energized the EDG starting circuit.

c. Conclusion

In August 1997, the "A" emergency diesel generator (EDG) inadvertently started during troubleshooting activities. The root cause of the event was a failure to establish enough detail in a maintenance related procedure (troubleshooting plan) to prevent an inadvertent EDG start. The licensee's corrective actions, included establishing adequate procedural controls over troubleshooting activities on safety-related equipment. The root cause evaluation was thorough, and the immediate and long term corrective actions were adequate. The failure to establish and implement adequate procedures in accordance with Technical Specification 6.8.1 was a violation of NRC requirements. This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-08-03)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the licensee entering the issue into their corrective action program. Licensee Event Report 50-336/97-027-00 is **closed**.

M8.2 (Closed) URI 50-336/97-208-02: Nuclear Instrument Drawer Calibration

a. Inspection Scope (92902)

The inspector reviewed the licensee's actions to address Unresolved Item (URI) 50-336/97-208-02. This URI was opened to determine if, by placing an elevated voltage test source on a wide range nuclear instrument (NI) drawer test point, the licensee could have damaged the NI instrumentation, affected its sensitivity or affected its calibration. The inspector conducted in-office, on-site, and in-field reviews, including a series of interviews. The in-field reviews included an inspection of the wide range NI drawers and test instrumentation, and observation of a portion of procedure SP 2401, "Wide Range Drawer Calibration." Condition Reports (CRs) M2-97-3016 and M2-98-0540 and Technical Review Memo MP2-I-98-018 were also reviewed.

b. Observations and Findings

Prior to the issuance of this URI, the licensee did not control the test instrument input voltage into the NI wide range instrumentation during the performance of procedure SP 2401. To evaluate this issue, the licensee prepared Technical Review Memo MP2-I-98-

018, dated February 20, 1999, which stated that a high amplitude signal, up to 10 volts, would not have an adverse effect on the signal processing circuitry in the wide range NI or the accuracy of its calibration. The technical review memo concluded that this determination was verified by testing under automated work order (AWO) M2-98-00216.

On June 22, 1999, the inspector observed portions of procedure SP 2401 and interviewed an instrument and controls supervisor, and the two technicians performing the test. The technicians used a NUCMEG PG-81 pulse generator to input pulses into a Log-C Wide Range Nuclear Instrument Channel instrument. During the observed test the pulse generator test source output voltage was maintained at approximately 5.0 volts. The technicians demonstrated to the inspector that the maximum output voltage of the pulse generator was limited by a combination of its design and the internal impedance of the NI drawer to less than 9.0 volts. Although the practice before this URI was to not control the maximum voltage output of the signal generator, the technicians controlled the voltage by oscilloscope trace and were well aware of the issue.

Based on the electrical prints provided to the inspector, an input of less than +/- 15 volts would be responded to adequately by an internal NI amplifier circuitry design grounding scheme and would result in no damage to the circuitry and no affect on the circuitry calibration/sensitivity. The inspector examined the circuit to ensure that the high input voltage would not saturate the circuit, which would affect the ability of the circuit to detect discrete pulses. An elementary short circuit analysis of the input amplifier and discriminator under saturated conditions was performed in order to estimate transistor short circuit currents. The short circuit currents arrived at through this calculation were less than half of the circuit design maximum power rating. Therefore, the inspector determined that the application of +/- 15 volts was not sufficient to place the circuit in saturation. Although Technical Review Memo MP2-I-98-018 did not address the impact of drawer temperature in its evaluation, the inspector further verified that the difference between nominal drawer temperature and the temperature selected as a basis in the licensee memo had no significant impact. The inspector also verified that the combination of test duration, test frequency, and voltage range limitations did not represent a potential for chronic test-induced damage, miscalibration, or loss of sensitivity of the NI circuitry.

c. Conclusion

The licensee actions were acceptable to address URI 50-336/97-208-02 which involved the failure to control the voltage output of a pulse generator test source applied to a wide range nuclear instrumentation (NI) drawer. Although the voltage of the pulse generator test instrumentation used during the testing was uncalibrated and uncontrolled by procedure SP 2401, the design of the test instrumentation combined with that of the NI drawer prevented the NI drawer from being damaged or having its sensitivity or calibration affected. Enhancements to procedure SP 2401 to confirm the output voltage of the pulse generator test source were determined to be acceptable. No violation of NRC requirements was identified. Unresolved Item 50-336/97-208-02 is **closed**.

M8.3 (Closed) LER 50-336/97-024-00 & -01: American Society of Mechanical Engineers (ASME) Section XI Surveillance Requirements

a. Inspection Scope (90712, 92700)

In-office and on-site document reviews were conducted of the licensee's corrective actions in response to the deficiencies described in Licensee Event Report (LER) 50-336/97-024-00 & -01.

b. Observations and Findings

The inspector reviewed LER 50-336/97-024-00 & -01; Condition Reports M2-97-1073, 97-024-01, 98-2616, 98-2809, and 98-2974; ASME code case N508-1- Rotation of Serviced Snubbers and Pressure Relief Valves for the Purpose of Testing; Regulatory Guide 1.147; and an NRC letter to the licensee, Evaluation of Relief Requests, dated July 1, 1998. The licensee's corrective actions included establishing adequate controls over the subject portions of Section XI surveillance testing and gaining NRC approval to use code case N-508-1 as an alternative to portions of ASME Section XI, paragraph IWF-5000.

Although there were some NRC identified issues related to LER 50-336/97-024-00, overall, the inspector found that the licensee appropriately reported and corrected the deficiencies in LER 50-336/97-024-01. The licensee's corrective actions adequately addressed three issues: (1) the application of code case N-508-1, (2) testing of four spool pieces installed in the service water system in 1990, and (3) leak testing of the hydrogen monitoring system. The corrective actions included procedural changes, implementation of additional testing, and gaining approval from the NRC to use specific code cases.

c. Conclusion

The licensee failed to meet certain portions of ASME Section XI surveillance requirements, as required by Unit 2 Technical Specifications (TS). The licensee's corrective actions included procedural changes, implementation of additional testing, and gaining approval to use specific code cases. The licensee properly reported, and corrected the deficiency. The root cause evaluation was thorough, and the immediate and long term corrective actions were adequate. The failure to meet the ASME Section XI testing requirements, as required by Unit 2 TS, was a violation of NRC requirements. This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-08-04)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the licensee entering the issue into their corrective action program. LER 50-336/97-024-00 &-01 is **closed**.

M8.4 (Closed) VIO 50-336/98-207-07 and LER 50-336/98-015-00: Failure to Test the Four Digital Liquid and Gaseous Effluent Radiation Monitors in a Manner Consistent with Technical Specifications

a. Inspection Scope (90712, 92700, 61726)

In-office and on-site record reviews were conducted to determine the licensee's corrective actions and response to Violation 50-336/98-207-07. The violation was issued because the licensee failed to test four digital liquid and gaseous effluent radiation monitors in a manner consistent with Unit 2 technical specification (TS) requirements. Specifically, the operability of the liquid and gaseous digital radiation monitors was not fully tested, because the ability of the amplifiers and/or analog-to-digital conversion circuitry to process the count rate signal at a higher pulse frequency was not verified during routine surveillances.

b. Observations and Findings

The inspector reviewed the licensee's response (B17350) and corrective actions associated with the violation; Automated Work Order (AWO) ME-98-2600; Condition Reports (CRs) M2-97-2860 and M2-98-1414; the licensee's updated root cause analysis; and special test procedures for the clean liquid radwaste effluent monitor, aerated liquid radwaste effluent monitor and condensate polishing facility water neutralizing sump monitor. In addition, a sample of existing procedures meeting TS channel function test requirements was reviewed. The licensee's corrective actions and response to the violation were found to be adequate. Further, the issue was found to be properly reported in Licensee Event Report 50-336/98-015-00.

c. Conclusion

Violation 50-336/98-207-07 was written to document an NRC identified failure to test the four digital liquid and gaseous effluent radiation monitors in a manner consistent with Unit 2 Technical Specification requirements. The violation was adequately responded to and reported by licensee. Violation 50-336/98-207-07 and Licensee Event Report 50-336/98-015-00 are closed.

M8.5 (Closed) LER 50-336/99-001-00: Failure to Perform a Required Surveillance on a Fire Door

a. Inspection Scope (90712, 92700, 92903)

The inspector performed an in-office and on-site document reviews of the licensee's failure to test a roll-up fire door in the barrier between the Unit 2 Turbine Building and Unit 1 Access Control Area that was reported in Licensee Event Report 50-336/99-001-00.

b. Observations and Findings

The Unit 2 Technical Requirements Manual (TRM) and selected fire protection related surveillances were reviewed. The inspector found that the missed fire door surveillance resulted from the door not being included in the population of doors addressed by the surveillance procedure. It was not included in the surveillance procedure population because the door was improperly labeled. The root cause of the improper labeling was a loss of configuration control.

The fire loading on either side of the door was determined to be less than one hour. The untested door was determined to have integrity and likely would have performed as designed. If the door failed to close properly, a second set of doors rated at 1.5 hours would have protected enclosed equipment, based on the fire loading on either side of the untested door. Therefore, there appears to be low safety significance to the missed technical specification (TS) required surveillance. In response to this issue, NU established a fire watch and implemented a plant modification of the doors on either side of the untested door to improve their rating. The licensee's corrective actions were determined to be adequate.

c. Conclusion

The licensee identified and reported that a TS required fire protection related surveillance of a specific Unit 2 roll-up fire door had not been routinely performed. The fire loading on either side of the door was determined to be low and tested doors on either side of the untested door provided adequate protection from the spread of fire. The licensee adequately identified, reported, and corrected this deficiency. The failure to perform a TS required surveillance is considered a minor violation and is not subject to formal enforcement action. Licensee Event Report 50-336/99-001-00 is **closed**.

U2.III Engineering

U2 E1 Conduct of Engineering

E1.1 Water Intrusion Into Oil Reservoir of "B" Auxiliary Feedwater Pump

a. Inspection Scope (62707)

On June 1, 1999, and again on June 4, 1999, the licensee declared the "B" auxiliary feedwater (AFW) pump inoperable when water was discovered in the outboard pump bearing oil reservoir. The inspector interviewed licensee personnel and reviewed historical documentation to determine whether the licensee was previously aware of the water intrusion concern and what actions had been taken to address the concern.

b. Observations and Findings

On June 1, 1999, after a high lube oil level was noted in the sight glass, approximately 5 ounces of water and 8 ounces of oil were drained from the "B" AFW pump outboard pump bearing oil reservoir (approximately 38% water). Approximately 8 ounces of oil is the normal amount of oil that would bring level up to the bottom of the duplex thrust bearing (back-to-back tapered roller bearings). The oil is splashed on the bearings by an oil flinger that rotates with the shaft as it dips into the oil supply. Condition Report M2-99-1783 was initiated describing the water intrusion and the pump was declared inoperable. The oil was changed and the housing was flushed. The licensee determined that water leakage from the pump packing gland was entering the bearing oil reservoir through the oil fill cap. Sealant was applied around the fill cap. During the post-maintenance run, high axial vibration readings (0.33 inches per second) were noted in the "B" AFW outboard pump bearing, which is in the Alert range per the inservice test program. Following the post-maintenance testing, the "B" AFW pump was returned to service.

On June 4, 1999, the analysis of the oil sample that was taken following the post-maintenance test run showed there was 3.5% water in the oil. Condition Report M2-99-1808 was initiated and the "B" AFW was again declared inoperable. The licensee determined that the water was not introduced during the post-maintenance test run but rather, the previous flush and refill was not effective in removing all the water. The licensee then performed several additional oil flushes and used hot air to evaporate any remaining traces of water. Following testing, the "B" AFW pump was again returned to service. Subsequent sampling showed only minute traces (0.045%) of water. Vibration readings taken during the post-maintenance test run were back to normal (out of Alert). Through interviews with licensee personnel and reviews of historical documentation, the inspector found that the licensee's corrective actions on June 1, 1999 were ineffective.

The inspector noted that the licensee missed prior opportunities to identify and correct the water intrusion problem. The sequence of events is documented below.

March 20, 1999	The "B" AFW was started but was secured 12 minutes later when smoke was observed emanating from the outboard pump packing gland. The licensee decided that replacing the packing was unnecessary. Instead, they loosened the packing gland to finger tight resulting in a greater flow of water from the packing gland. Maintenance personnel wanted to keep the packing gland loose because of past problems with overheating when the packing gland was adjusted to reduce leakage. Although the previous sample on January 18, 1999, showed less than 0.05% water, the system engineer discussed with the Condition Based Maintenance (CBM) Technician, who takes the oil samples, that there was a greater potential for water entering the oil reservoir due to the increased pump packing leakage.

March 20,1999, to April 12, 1999	The "B" AFW was operated on 13 separate occasions for a total of approximately 40 hours.
April 12, 1999	The outboard bearing oil reservoir was drained for a scheduled oil change. Maintenance personnel noted that the oil had a significant amount of water in it and that the level indicator was showing a high level before the draining. The oil reservoir was refilled and Trouble Report 12M2145947 and Automated Work Order (AWO) M2-99-04846 were generated to obtain a sample following the next pump run. Maintenance personnel provided the drained oil to the CBM Technician to be sent out for analysis. The CMB Technician stated that he did not send out the sample for analysis, because so much water was visible that the sample was obviously bad The only action that was taken to address the deficient condition was to prepare an automated work order to sample the oil after the next pump run rather than wait for the next quarterly analysis. No condition report was generated to document the adverse condition. The inspector determined that licensee's corrective actions were inadequate in that the licensee failed to initiate a condition report and address the water intrusion problem.
April 12, 1999 to May 11, 1999	The "B" AFW pump was operated on 5 separate occasions for a total of approximately 12 hours. An oil sample taken on May 11, 1999, showed less than 0.05% water.
May 11, 1999 to June 1, 1999	The "B" AFW pump was operated on one occasion for approximately four days.
June 1, 1999	As described above, the oil sample showed that 5 ounces of water had entered the reservoir and the "B" AFW pump was declared inoperable. However, the licensee determined that the condition was not reportable per 10 CFR 50.73.
June 4, 1999	As described above, the analysis of the oil sample that was taken following the post-maintenance test run three days earlier showed there was 3.5% water in the oil, and the "B" AFW was again declared inoperable.

The inspector performed additional reviews of historical documentation and found that water intrusion into the AFW pumps oil reservoirs has been a longstanding recurrent problem.

1979	As discussed in Licensee Event Report (LER) 50-336/79-17, in 1979, the inboard bearing on the "B" AFW pump failed and the shaft was damaged due to contamination of the bearing oil with water. Water entered the bearing housing either down the shaft of the pump or through the fill port

of the bearing oil reservoir due to excessive packing leakage. The LER stated that, as a long term corrective action, mechanical seals on the pump were being investigated. Project Assignment 79-218 was initiated to convert the AFW pumps from packing to mechanical seals, but was never implemente.

1985	The "A" AFW pump bearings were replaced twice as a result of water contamination.
1989	After the vibration on the pump outboard bearing on the "A" AFW pump was found to be out-of-specification, a visual inspection of the bearing showed a moderate wear and a light frosted appearance, indicative of water contamination.
1993 to 1994	Water intrusion on the "B" AFW pump was a recurrent problem with sample results as follows: four percent on December 29, 1993, four percent on July 19,1994, and six percent on October 18, 1994.
1994	The licensee performed a thorough root cause investigation (Plant Information Report 2-94-112) of the "B" AFW pump outboard pump bearing when the oil was darkened due to wear related particulate. A secondary cause described in the report was inadequate design in that the pump packing leakoff makes the bearings susceptible to water contamination.
1996	The system engineer submitted a request to modify the "B" AFW pump to install mechanical seals to eliminate the pump packing leakoff problems that caused the water in the bearing oil. The modification was characterized as an enhancement and was not approved for the mid-cycle 13 refueling outage.

Based on the above, the inspector determined that the licensee's corrective actions were inadequate when water was identified on April 12, 1999, and that water intrusion has been a longstanding recurrent problem that the licensee had not effectively addressed. The inspector was also concerned that the licensee had not evaluated the operability of the "B" AFW pump for the period from March 20, 1999, when the "B" AFW pump outboard packing was loosen to finger tight, to June 1,1999, when the oil fill cap was sealed.

The inspector discussed the historical operability concern, as well as the missed opportunity to address the water intrusion on April 12, 1999, with licensee management. The licensee generated a Level 1 Condition Report M2-99-1900 and established a Root Cause Team to evaluate the inspector's concerns. The Root Cause Team evaluated the period from March 20 to June 1 and determined that the pump remained operable and therefore, the water intrusion condition was not reportable. The licensee's basis for concluding the "B" AFW pump was operable is as follows:

(1) Technical Specifications require all three AFW pump to be operable while in Operational Modes 1, 2, and 3. During the period in question, the plant was in Modes 1, 2, or 3 for two periods, March 31 to April 6, 1999, and April 25 to June 1, 1999, the AFW pumps would be required to remain operable post-accident for the ten hour period of time to cooldown the plant. Assuming a single failure of the "A" AFW pump or the turbine driven AFW pump, the "B" AFW would be required to operate for this ten hour period.

(2) An evaluation by the licensee's Safety Analysis Branch (SAB) dated June 22, 1999, showed that after ten hours of cooldown, only one AFW pump is required to provide a secondary method (primary is the shutdown cooling system) of decay heat removal for an indefinite period. After ten hours, the "B" AFW could be lost as dependent occurrence as a result of the loose packing condition leaving either the "A" AFW pump and turbine driven AFW pump available for the decay heat removal safety function. During this indefinite period of time following the ten hour cooldown, maintenance activities to repair a failed pump would be permitted.

(3) Since no bearing damage or oil emulsification was experienced with up to five ounces of water during the four day run beginning May 25, 1999, it is reasonable to conclude that the additional water accumulation that would occur during the ten hour plant cooldown would not prevent pump operation. Therefore, the licensee concluded that the "B" AFW pump remained fully capable of delivering auxiliary feedwater flow under design basis accident conditions.

The licensee's subsequent reportability determination stated that based the technical assessment, the "B" AFW pump was operable and was not in a condition adverse to safety and the water intrusion deficiency was not reportable. In addition, the licensee downgraded Condition Report M2-99-1900 from Level 1 to Level 2 which allowed them to suspend their efforts in performing a root cause evaluation and did not require corrective actions to prevent recurrence. The inspector determined that it was inappropriate to downgrade the condition report from a Level 1 to a Level 2 given the fact that water intrusion has been a long term recurrent problem. The licensee agreed that downgrading the condition report from Level 1 to a Level 2 was inappropriate and generated a Level 1 Condition Report M2-99-2265 to document the issue.

The inspector also determined that the licensee did not provide a sufficient basis for determining the "B" AFW pump was operable during the period in question. Unit 2 Technical Specification Definition 1.6, "OPERABLE - OPERABILITY," states a system, train, or component shall be OPERABLE when it is capable of performing its "specified function(s)". The Final Safety Analysis Report (FSAR), Section 14.6.5.3.3, describes the major assumptions used in the small break loss of coolant accident (LOCA) with respect to Long-Term Cooling. FSAR, Section 14.6.5.3.3, Assumption 7 states that a continuous supply of AFW is available for the duration of steam generator cooling and one turbine-driven and one motor-driven AFW pump are assumed to be in operation. Even though the "B" AFW pump would have failed sometime after ten hours, the licensee inappropriately determined that this component was operable, based on the fact that the

AFW system would have performed its specified function of long term core cooling post-LOCA utilizing the redundant AFW pumps. The licensee agreed with the inspector's concern and prepared Condition Report M2-99-2273 to reassess operability and reportability determinations of the "B" AFW pump for the period in question.

The inspector concluded the risk significance of this water intrusion event was low based on several considerations. During the period before May 29, 1999, the "B" auxiliary feed pump (AFP) could have operated for a minimum of four days, as indicated by the actual operation of the pump from May 25 to May 29. The licensee determined that, during the subsequent period between May 29, 1999 and June 1, 1999, the "B" AFP would have operated for at least ten hours, based on the lack bearing damage and oil emulsification. The inspector concluded that this licensee determination was reasonable. Therefore, the system function of decay heat removal during the short term would have been achieved. The other two AFPs were operable and would have provided long term removal of decay heat. Also, the residual heat removal system was operable and would have provided long term cooling of the plant.

c. Conclusion

The licensee failed to initiate a condition report and implement effective corrective actions when a significant amount of water was identified in the oil removed from the outboard bearing of the "B" auxiliary feed water pump during a scheduled oil change on April 12, 1999. As a result, the condition recurred during continuous operation of the pump from May 25 through 29, 1999, and the degraded condition was not identified and corrected until June 1, 1999. In addition, the licensee's assessment of operability during the period prior to June 1, 1999, was not well founded in that it was based on the ability of the system, rather than the component, to perform its design function. Finally, the licensee inappropriately used the conclusion that the pump had been operable as a basis to reduce the degree of thoroughness in identifying and implementing corrective actions to address the recurrent problems with water intrusion. The failure of the licensee to implement adequate corrective actions to address the water intrusion problems on April 12, 1999, is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-08-05)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the licensee entering the issue into their corrective action program.

E1.2 Repair of the Reactor Building Closed Cooling Water Outlet Isolation Valve from the "B" Containment Air Recirculation Cooler

a. Inspection Scope (37551/62707)

The inspector reviewed automated work order (AWO) M2-99-08153 for repair of valve 2-RB-29B, the reactor building closed cooling water (RBCCW) outlet isolation valve from the "B" containment air recirculation (CAR) cooler, and associated engineering documents with respect to RBCCW system design requirements and Unit 2 Technical Specification requirements. The inspector observed post-maintenance testing activities

associated with valve 2-RB-29B from the control room and interviewed operations and engineering department personnel involved with the testing.

b. Observations and Findings

While restoring from maintenance affecting the "B" CAR cooler, operators identified that the manual operator for valve 2-RB-29B, the RBCCW outlet isolation valve from the "B" CAR cooler, was broken. This valve is one of many throttle valves used to balance RBCCW system flow to assure that all safety-related components would receive adequate flow during postulated accident conditions. With the manual operator broken, the Unit Supervisor was not confident that the RBCCW flow balance could be maintained because the throttle valve position could not be verified. Consequently, he declared the "B" RBCCW train inoperable. Operators subsequently isolated flow through valve 2-RB-29B, which restored the "B" RBCCW train to an operable condition and rendered the "B" CAR cooler inoperable. The operators that identified the broken valve operator documented the problem in condition report (CR) M2-99-1989.

With flow isolated through valve 2-RB-29B, maintenance personnel repaired the valve operator under AWO M2-99-08153. Operators then positioned the valve as specified in procedure SP 2611D, "RBCCW System Alignment Checks, Facility 2," which specified the required position of valve 2-RB-29B as eight and one-half turns open. When operators restored flow through 2-RB-29B, they observed that flow through the "B" CAR cooler was about 2200 gpm, which was above the acceptance criterion of 1950 to 2000 gpm specified in the retest section of the AWO.

Instead of documenting the failure to satisfy the post-maintenance test acceptance criteria in a new CR, which would have required an operability evaluation for this condition, the operators contacted engineering about the high flow through the "B" CAR cooler. In response, engineering provided a condition report engineering disposition (CRED) associated with CR M2-99-1989, which described the broken valve operator. The CRED listed steps to establish a new throttle position for valve 2-RB-29B that would provide acceptable flow through the "B" CAR cooler. The CRED also specified revising procedure SP 2611D to document the new throttle position of valve 2-RB-29B.

During a control room tour, the inspector noted that flow through the "B" CAR cooler was higher than normal and that operators were preparing to establish a new throttle position for valve 2-RB-29B under AWO M2-99-01853 using the steps listed in the CRED. The inspector was concerned that the RBCCW train was in service and considered operable while flow to the "B" CAR cooler was being adjusted, which created the potential for providing insufficient cooling flow to other components. The inspector raised this concern with the Shift Manager and the operations department test lead. The Shift Manager consulted with engineering personnel and concluded that the train would be operable during the evolution and that the AWO and CRED provided acceptable controls on the evolution. The operators established a new throttle position for valve 2-RB-29B of five and one-quarter turns open, which provided flow rates within the criteria specified in the retest section of the AWO, and prepared a revision to procedure SP 2611D to document this position as the new required position for the valve. After further

evaluation, the inspector developed the following concerns regarding the operability of the "B" RBCCW train:

(1) From the time that flow was restored to the "B" CAR cooler until the time that the position of valve 2-RB-29B was reset, the operability of "B" train of RBCCW was in question, because the flow to the "B" CAR cooler was potentially high enough to reduce flow to other safety-related components, such as the "B" shutdown cooling heat exchanger, below their design values established to mitigate postulated accidents.

(2) During the evolution to establish the new throttle position of valve 2-RB-29B, operators changed the flow balance of the "B" RBCCW loop while it was in service and considered operable. The AWO and associated CRED used to perform the evolution were not plant procedures and they had not received the review and approvals that were required for procedures. In addition, the instructions in the CRED were used to reposition valve 2-RB-29B to a position inconsistent with the approved surveillance procedure for verification of "B" RBCCW train operability, procedure SP2611D.

The inspector discussed these concerns with the responsible system engineer. The system engineer confirmed that the RBCCW flow to the "B" CAR cooler was above its design limits before the new throttle position of valve 2-RB-29B was established. The system engineer stated that, because the RBCCW flow values and valve configuration were not consistent with design documents and approved procedures, the affected train should have been declared inoperable until the discrepancies were resolved and that initiation of a condition report describing the test failure was the appropriate mechanism to initiate the necessary operability evaluations. However, the system engineer believed that additional analyses would have demonstrated acceptable performance of safety-related components throughout the evolution, although with reduced margin. The system engineer also considered that the AWO and CRED were sufficiently limited in scope that performance of the specified actions did not adversely affect the operability of the RBCCW train.

The inspector reviewed RBCCW system flow distribution design calculations, the flow rates established during flow balance testing of the RBCCW system, and recorded flow rates through the "B" and "D" CAR coolers, which receive flow from the "B" RBCCW train, before and after establishment of the new throttle position for valve 2-RB-29B. The inspector found that the margin established for safety-related components during flow balancing of the RBCCW system was adequate to accommodate the flow reduction likely to result from operation with the RBCCW flow to the "B" CAR cooler above the acceptance criteria specified in the post-maintenance test.

The inspector reviewed the licensee's reporting requirements for conditions adverse to quality. Section 1.5 of administrative procedure RP4, "Corrective Action Program," requires plant personnel to initiate condition reports for conditions that have a potential or actual adverse effect on plant safety. Appendix B to 10 CFR Part 50, Criterion V, "Instructions, Procedures, and Drawings," requires that activities affecting quality shall be

accomplished in accordance with documented procedures. The inspector found that the failure to initiate a condition report following the failure of the post-maintenance test, as required by administrative procedure RP4, was a violation of 10 CFR Part 50, Appendix B, Criterion V. This failure directly contributed to the licensee not thoroughly assessing operability of the "B" RBCCW train while it was operating in an unanalyzed flow distribution and to the licensee inappropriately implementing a CRED to establish the new throttle position for valve 2-RB-29B while the "B" RBCCW train was in-service.

c. Conclusions

Following the repair of a reactor building closed cooling water (RBCCW) throttle valve, the licensee failed to initiate a condition report when RBCCW flow to the "B" containment air recirculation cooler significantly exceeded the post-maintenance acceptance criteria. Because this higher flow rate could have resulted in insufficient RBCCW flow to other safety-related components, a condition report was necessary to initiate an operability assessment of the "B" RBCCW train, which was in service. Although a subsequent evaluation showed that the RBCCW flow to other safety-related components would have remained within established margins, the failure to initiate a condition report, as required by the licensee's administrative procedure governing the corrective action program, is a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-08-06)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the licensee entering the issue into the corrective action program. This violation is in the licensee's corrective action program as Condition Report M2-99-2985. In addition, rather than using an approved procedure, an engineering disposition was inappropriately used to provide instructions to manipulate the in-service RBCCW system to establish a new throttle position for the repaired valve.

E1.3 Year 2000 Project Readiness Review

During this inspection period, a review was conducted of the Millstone Y2K activities and documentation using Temporary Instruction (TI) 2515/141, "Review of Year 2000 (Y2K) Readiness of Computer Systems at Nuclear Power Plants." The review addressed aspects of Y2K management planning, documentation, implementation planning, initial assessment, detailed assessment, remediation activities, Y2K testing and validation, notification activities, and contingency planning. The reviewers used NEI/NUSMG 97-07, "Nuclear Utility Year 2000 Readiness," and NEI/NUSMG 98-07, "Nuclear Utility Year 2000 Readiness Contingency Planning," as the primary references for this review.

The results of this review will be combined with similar reviews of Y2K programs at other U.S. commercial nuclear power plants and summarized in a report to be issued by the NRC staff in September 1999.

U2 E8 Miscellaneous Engineering Issues

E8.1 (Closed) VIO 50-336/95-42-04: Intake Structure Ventilation System Deficiencies

a. Inspection Scope (90712, 92700, 92903)

In-office, in-field and document reviews were conducted of the licensee's corrective actions to resolve a potential for the Unit 2 intake structure temperature to rise from 115°F to 176°F during certain plant conditions. The licensee's initial response to this potential intake structure elevated temperature condition was addressed in Violation 50-336/95-42-04.

b. Observations and Findings

Licensee Event Report (LER) 50-336/95-03 reported that under certain postulated scenarios, the intake structure design temperature of 115°F could be exceeded. The postulated scenarios involved a partial or total loss of the three intake structure non category 1 exhaust fans without the loss of the three non category 1 circulating water pumps, which are the primary source of heat for the room. Failure of all three exhaust fans was assumed because they are powered from non vital power supplies, with two of the fans powered from the same bus. With circulating pumps running, the intake structure was estimated to reach 176°F if all three exhaust fans were lost. The intake structure design temperature of 115°F was based on the maintenance of service water pump motor insulation integrity. The licensee determined that the service water pump motors could operate 24 hours with an ambient temperature of 176°F with negligible service life degradation.

Violation 50-336/95-42-04 was issued, because the licensee failed to promptly correct the deviation of the design basis temperature from 115°F to 176°F or prepare a timely written safety evaluation describing whether the elevated intake structure temperatures involved an unreviewed safety question. In part, the licensee's corrective actions for the violation included a modification to the intake structure. The inspector verified that licensee installed two passive roof ventilators in the Unit 2 intake structure roof, which would limit the room temperature to 130°F, established a procedure to address the configuration and use of the ventilators, and completed calculations (HI-971802) that indicate a maximum room temperature of 130°F is acceptable.

The inspector found that the licensee appropriately corrected the deficiency and adequately responded to the violation. Violation 336/95-42-04 is closed.

c. Conclusion

The licensee's corrective actions to resolve a potential increase in intake structure air temperature which included additional engineering analysis and modifications to the intake structure were found to be adequate. Therefore, Violation 50-336/95-42-04 is closed.

E8.2 (Closed) LER 50-336/97-021-00: Non-Quality Assurance (non-QA) Lamps Installed in the QA Category I Reactor Protection System

a. Inspection Scope (92700, 90712, 92903)

In-field, in-office and on-site record reviews were conducted to evaluate a Reactor Protection System lamp failure reported in Licensee Event Report (LER) 50-336/97-021-00.

b. Observations and Findings

The licensee reported that it had identified a failed non-QA lamp installed in a QA circuit. Based on the data reviewed, the inspector found that the licensee's root cause conclusion was adequate. The root cause was that the licensee inadequately established its scope of review in response to NRC Information Notice (IN) 94-68: Safety Related Equipment Failures Caused by Faulted Indicating Lamps. Although the inspector came to the same root cause, it should be noted that NRC IN 94-68 contained only suggestions that were not NRC requirements; therefore, no specific action or written response was required.

Subsequent to the lamp failure, the licensee conducted a review of the affected lamps in accordance with the licensee's specification SP-ST-ME-944, "Material, Equipment, and Parts Lists (MEPL) for In-Service Nuclear Generation Facilities." MEPL controls the engineering and assessment process for classifying structures, systems, components, parts, materials, quality software, activities or consumables that need to be safety related or of augmented quality. The inspector reviewed the MEPL evaluation for the affected lamps and verified that it was placed in automated work order (AWO) M2-98-01183. This AWO, which remains in the Unit 2 control room, contains a list of qualified lamps that operators are allowed to replace as necessary. The presence of the AWO in the Unit 2 control room was verified and operators were interviewed about its use. In addition, the lamp list in the control room was verified by the inspector against that produced by the most current MEPL review and the lamp lists were determined to be consistent.

c. Conclusion

In 1997, the licensee identified and reported that a failed, non-quality assurance (non-QA) lamp was installed in a QA circuit and had to the potential to affect the performance of safety-related circuits. The failure of the licensee to implement appropriate quality standards and measures for the selection and review of suitability of application of material, parts, equipment, and processes that essential to the safety-related functions of systems and components is a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control." This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-08-07)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the licensee entering the issue into the corrective action program. LER 50-336/97-021-00 is **closed**.

E8.3 (Closed) LER 50-336/97-025-00: Condensate Storage Tank (CST) Single Failure

a. Inspection Scope (90712, 92700, 92903)

In-office, in-field and document reviews were conducted of the licensee's corrective actions in response to a postulated single failure in the hotwell return line from the Condensate Storage Tank (CST), which could possibly affect the operability of the Auxiliary Feedwater system (AFW) and was reported in Licensee Event Report (LER) 50-336/97-025-00.

b. Observations and Findings

The inspector reviewed a reported condition involving a postulated single failure of a condenser hotwell makeup valve. The licensee identified that a single failure of a hotwell makeup valve (2-CN-241) could cause a diversion of water from the CST below the level that which would ensure a sufficient water supply for the AFW system. The licensee's corrective actions, as described in Condition Report M2-97-1173, included establishing adequate controls over the subject valve by closing upstream and downstream block valves and establishing a revised makeup path.

The inspector found that the licensee appropriately reported and corrected the deficiency. The root cause evaluation was thorough, and the corrective actions were adequate.

c. Conclusion

In 1997, the licensee identified that a postulated single failure of a condenser hotwell makeup valve would cause a diversion of water from the CST and impact the availability of sufficient water for the AFW system to perform its safety function. The licensee took appropriate corrective actions. The failure to establish appropriate design controls to ensure that safety-related equipment would function as assumed in the Unit 2 Final Safety Analysis Report is a violation of 10 CFR 50, Appendix B, Criteria III, "Design Control." This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-08-08)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the licensee entering the issue into the corrective action program. Licensee Event Report 50-336/97-025-00 is **closed**.

E8.4 (Closed) LER 50-336/98-001-00:Vital 120 Volt AC System Fault Clearing Coordination

a. Inspection Scope (90712, 92700, 92903)

In-office and on-site document reviews were conducted of the licensee's corrective actions in response to a potential vital 120 volt AC system fault clearing coordination problem, which could result from a postulated High Energy Line Break (HELB) or seismic design basis accidents. This condition was reported in Licensee Event Report (LER) 50-336/98-001-00.

b. Observations and Findings

The inspector reviewed a reported potential condition (120 volt vital AC electrical fault isolation) resulting from a postulated HELB or seismic design basis accident. This LER reported additional corrective actions and conditions beyond those reported in LER 336/94-026. The licensee's corrective actions as described in Condition Report M2-98-0056, included electrical modifications and additional analysis. The inspector found that the licensee appropriately reported the deficiency. The root cause evaluation was thorough, and the corrective actions were adequate.

c. Conclusion

The licensee identified that, under some postulated HELB or seismic design basis accident conditions, the isolation of 120 volt vital AC electrical faults could not be ensured. The licensee appropriately reported and corrected the deficiency. The root cause evaluation was thorough, and the corrective actions were adequate. The failure to ensure that safety related equipment (120 volt vital AC) was designed in accordance with 10 CFR 50, Appendix B, Criterion III, "Design Control," to adequately respond to design basis accidents, is a violation of NRC requirements. This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-08-09)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the licensee entering the issue into the corrective action program. Licensee Event Report 50-336/98-001-00 is **closed**.

E8.5 (Closed) LER 50-336/98-007-00 & -01: Reanalysis of Final Safety Analysis Report (FSAR) Main Steam Line Break Analysis Indicates Possible Fuel Failures

a. Inspection Scope (92700, 92712, 92903)

The inspector conducted in-office and on-site document reviews of the licensee's actions to address a condition outside the design basis associated with a postulated main steam line break that was reported in Licensee Event Report (LER) 50-336/98-007-00 & -01.

b. Observations and Findings

The inspector reviewed Condition Report M2-98-1026, which identified an inadequate calculation of limiting power distributions in the FSAR Main Steam Line Break Analysis for cycle 13. Fuel cycles subsequent to cycle 10 involved radial power distributions that exceeded those used in the FSAR. The licensee's corrective actions in response to this discovery included an LER and a technical specification change proposal that resulted in License Amendment 228. The incremental radial power distribution changes from cycle to cycle resulted from core and fuel loading design changes that impacted FSAR Section 14.1.5, Main Steam Line Break Accident Analysis, and posed a potential to violate either the fuel clad temperature fuel design limit or a departure from nucleate boiling fuel design limit during a postulated design basis main steam line break. The inspector found that the licensee adequately reported and resolved the postulated condition.

c. Conclusion

The licensee identified and reported inadequate calculations of limiting power distributions in Main Steam Line Break Analysis for cycle 13. As part of its corrective action, the licensee adequately reported the deficiency, requested a TS change and received a license amendment to resolve the deficiency. The failure to perform an adequate main steam line break analysis is a violation of 10 CFR 50 Appendix B, Criterion III, "Design Control." This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-08-10)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the licensee entering the issue into the corrective action program. Licensee Event Report 50-336/98-007-00 & -01 is **closed**.

Report Details

Summary of Unit 3 Status

Unit 3 began the inspection period in refueling outage 6 (RFO6) in operational Mode 6 (Refueling). The reactor was taken critical on June 26 and placed online June 29. Various required surveillances and tests were performed at selected power plateaus. 100 percent power was achieved on July 4. Operators reduced power to 90 percent on July 10 to perform thermal backwashes of the condenser hotwells. Power was subsequently restored to 100 percent the next day, where it essentially remained through the end of the report period on August 9.

U3.I Operations

U3 O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations, including operator and shift crew performance of surveillance activities and other operational evolutions; walkdowns of the main control board; inspection-tours of several plant areas and all buildings housing safety-related systems; and observations of a sample of planning and shift turnover meetings, pre-job briefings, and selected plant operations review committee (PORC) and other licensee management meetings. Inspectors witnessed control room operations with the direct observation of communications inter-departmental liaison, component swaps within safety trains, and safety system restorations. Certain operational activities (e.g., rod drop testing) were observed on mid-shifts and other off-shift hours. The inspectors evaluated the licensee performance of planned evolutions and the response to plant transients with respect to technical specification (TS) compliance, technical requirements manual (TRM) provisions, and the overall conduct of operations in accordance with approved procedures and process controls. Specifically the following work activities were observed:

- control and tagging of the steam generator containment penetration boundaries in accordance with operations procedure, OP 3250.12;
- the draining and movement of refueling water consistent with OP 3305;
- control of the power lockout switches for valve position on several emergency core cooling system (ECCS) valves, consistent with routine operations and the performance of a surveillance procedure for the train "A" residual heat removal (RHR) pump;
- reactor startup in accordance with procedure OP 3202, with dilution to criticality controlled by an infrequently performed test or evolution (IPTE) engineering procedure, EN 31028;

- plant startup, to include power increases and synchronization of the main generator to the electric power grid, in accordance with procedure OP 3203;

- valve positioning for the water supply lines and impact of repair work on a relief valve discharge line, relative to the operability of the turbine driven auxiliary feedwater pump;

- performance of rod drop testing in accordance with surveillance procedure (SP 2451N22) controls;

- performance of daily and shiftly control room rounds (Modes 1 -4) in accordance with SP 3670.1-1;

- tagging controls for equipment isolated for maintenance (e.g., chilled water system power supply), equipment locked into a safety position (e.g., refueling water storage tank manual supply valve), and equipment tagged out for personnel safety concerns (e.g., commercial diving operations);

- handling and disposition of selected condition reports (e.g., CR M3 99-2861) impacting safety system operability.

- response to high condensate pump discharge oxygen levels, in accordance with chemistry procedure CP 3802B, Secondary Chemistry Control.

During the inspection of the above operational activities and in the follow-up of inspection questions, several operations department mangers, licensed operators and technical support personnel were interviewed, along with reactor engineers and other department personnel involved with the relevant procedures. As necessary, computer generated data (e.g., T_{avg} vs. reactor power plots) were requested for review in support of the inspection of changing plant conditions and operational evolutions. Specific questions and issues that required follow-up inspection are discussed in greater detail in the following paragraphs.

During a walkdown of the main control board, the inspector noted that all six circulating water pumps were operating, when it had been announced that contractor divers were in the water at the Niantic Bay Unit 3 intake structure. The inspector discussed this situation with the operators on shift and followed up in additional discussion with the Station Director of Maintenance, confirming that the work being performed by the divers was outside the trash racks and not in proximity to any of the operating pumps. The inspector reviewed the Millstone Common Maintenance Procedure (C MP 701B, Revision 1), noting that while the procedure delineates consultation with the licensee's safety department, the requirement for which "plant equipment must not be operated during dive" was not clear. Subsequently, the inspector conducted an interview with a licensee safety engineer, who provided a copy Revision 2 of C MP 701B, dated July 30, 1999. In this version of the procedure, it is clearly stated that the "tagging clearance will remove from service all plant equipment that may be hazardous to the diving operation." The safety engineer indicated that a "Commercial Diving Safety Review Checklist" has

been added to the revised procedure, enhancing all safety controls, to include equipment tagging requirements, job reviews, diver briefings, and dive site inspections. The safety engineer also indicated that some additional changes to the procedure might be forthcoming based upon the Safety Department's review of this procedural revision and the attached checklist. The inspector had no additional questions regarding the current safety requirements published for the control of commercial diving activities.

In reviewing reactor and plant startup operations, the inspector confirmed the use of the surveillance procedure, SP 3601G.3, for "T_{avg} Monitoring" during plant heatup , in accordance with TS 4.1.1.4 requirements, prior to the main turbine generator being placed on line. During the reactor power increase to 25%, the inspector observed the steam dumps placed in the "steam pressure" mode with the steam generator (S/G) pressure controller in automatic, as was delineated in the Plant Startup procedure, OP 3203. Since the S/G setpoint pressure was chosen to correspond to "no load" T_{avg} conditions, the inspector questioned how delta-T (T_{avg} - T_{ref}) was maintained within the temperature band assumed by the plant accident analysis if power were increased without adjusting the S/G pressure control setpoint to account for the increase in load. The inspector noted that prior to the main turbine generator being placed on line, the T_{ref} point, taken off of the turbine impulse pressure, is not available; therefore, the question was one of analyzed, not observable, conditions.

The cognizant reactor engineer produced temperature plots during the recent plant startup following RFO6, confirming that delta-T remains within the analyzed temperature band. The reactor engineer indicated that he had further discussed this with Westinghouse personnel, verifying that the accident analysis bounds the observed and theoretical conditions for power increases up to approximately 22%. The inspector verified that the OP 3203 steps provide for the main generator on line prior to 20% power, thus assuring that any unacceptable T_{avg} - T_{ref} deviation would be available for operator response and correction. Therefore, while the licensee's procedural approach to increasing reactor power to about 20% results in higher T_{avg} temperatures than would be the case if the S/G steam pressure setpoint were adjusted with power increases, the inspector confirmed that the resulting plant conditions were bounded by the plant design bases.

The inspector also reviewed the licensee's actions after entry into a TS Action Statement on June 22, 1999, as a result of the failure of a power-operated relief valve (PORV) during a surveillance test. Specifically, the valve failed to meet the applicable time requirement when the valve was stroked in the closed direction. The inspector subsequently determined that the licensee had appropriately reviewed the design criteria, noting that the design-basis function of the valve applied to only the open-stroke of the PORVs. Therefore, entry into the TS Action Statement was not required for the identified non-conforming condition. In addition, the inspector reviewed the licensee's engineering evaluation that formed the basis for dispositioning this non-conforming condition, the institution of procedure changes to remove the close-stroke acceptance criteria, as well as the compensatory measures established in the short term to resolve the issue. The inspector determined that the licensee's actions were both appropriate and acceptable.

Additionally, the inspector conducted discussions with the Unit 3 Operations Manager regarding the status of procedures located in satellite field locations (e.g., at the auxiliary shutdown panel) and regarding feedback to the shift operators when a CR raises questions about design-basis operating assumptions, as was the case for CR M3-99-2861. In this same vein, discussions were held with the licensee staff concerning the conditions deemed necessary by the licensed operators for exiting a TS Limiting Condition for Operation (LCO) when the same component or system is rendered inoperable for separate reasons.

Normally, when the ventilation system supporting a TS component is taken out of service for preventive maintenance, the component is scheduled for maintenance at the same time, because either set of work conditions renders the component inoperable. However, during this inspection period, due to other system equipment unavailability, the planned maintenance activities on the train "B" quench spray (QSS) pump ventilation system was accomplished before the quench spray pump was ready for its maintenance work. Both maintenance activities required entry into the Action Statement of TS 3.6.2.1 with an allowable outage time (AOT) of 72 hours. Initially it appeared that the licensee planned to complete the ventilation work, exit the LCO, then immediately re-enter the LCO for the pump work, with the belief that the 72 hour AOT had been reset. The inspector discussed this with the Operations Manager, who indicated that re-setting the AOT timing in such a case was not consistent with the Station policy for entry/exit from LCOs for planned maintenance activities. Subsequently, the maintenance work on the QSS pump was delayed to the following work week.

The inspector confirmed with the Station Regulatory Affairs Manager his concurrence with the Unit 3 Operations Manager's position, and further discussed the need for such regulatory decisions to be institutionalized for operations or other staff review and training. The Regulatory Affairs Manager indicated that actions had been initiated to promulgate, when required, regulatory "position papers", approved by PORC, when such questions of interpretation arise. The inspector noted that a previous question on "cascading TS" had been addressed by such a Regulatory Compliance Position. However, this previous position was published in the form of an internal licensee memorandum, which did not appear to provide the best format for the dissemination of readily available guidance to the operating shifts. With the licensee's intent to seek PORC approval for such Regulatory Affairs and Compliance (RAC) documents, it appears that a standard format for publishing and issuing such guidance would be beneficial for both training purposes and actual operator and operations department use.

Condensate pump discharge dissolved oxygen levels reached Action Level 1 limits (greater than 10 ppb) following the Unit 3 restart. Secondary chemistry control is important to minimize the corrosion rate of the secondary plant and to maintain the material integrity of the steam generators. As such, entering various action levels has an effect on the long term life of equipment, not on immediate operability. Although there are no direct technical specification requirements with regard to dissolved oxygen level, TS 6.8.4.c requires a secondary water chemistry program. This requirement is satisfied by the licensee's procedure governing secondary chemistry controls, CP 3802B. The inspector confirmed actions to identify oxygen inleakage paths were taken and timing in

the associated action level was appropriately tracked. Although the licensee took corrective actions to seal the turbine seals, elevated oxygen concentration was a recurring problem throughout the report period. The licensee prepared and was implementing an action plan to perform further equipment walkdowns and sealing activities at the end of the report period. The inspector had no safety concerns in this area.

Overall plant operations and specific operational evolutions were well controlled during this inspection period. While the plant challenges requiring the unplanned entry into TS action statements were few, the plant operators and management responded to these events in a deliberate, yet timely, and conservative manner.

U3 O7 Quality Assurance In Operations

O7.1 Review of Nuclear Oversight Activities (40500)

The inspector observed a licensee management exit briefing on June 25, 1999, which was conducted by a Joint Utility Management Assessment (JUMA) team. The JUMA team performed an assessment of the site Nuclear Oversight organization's implementation and compliance with 10 CFR 50, Appendix B, Quality Assurance Criteria For Nuclear Power Plants, which satisfied an annual management review requirement contained within the Northeast Utilities Quality Assurance Program (NUQUAP). In addition, the inspector reviewed the 1999 JUMA report that detailed the results of the JUMA assessment, which covered the time period June 21 - June 25, 1999. Overall, the inspector concluded that the broad, programmatic JUMA observations and findings were consistent with the NRC's current assessment of the site Nuclear Oversight organization.

On June 30, 1999, the licensee submitted for the Millstone Dockets, Revision 21 of the Northeast Utilities Quality Assurance Program (NUQAP) Topical Report for NRC review and approval. It is noted that the NU position of Recovery Officer - Nuclear Oversight has been eliminated and all oversight management responsibilities are being organizationally fulfilled by the Vice President - Nuclear Oversight and Regulatory Affairs, and the Director - Nuclear Oversight. This revision of the NUQAP was submitted pursuant to the requirements of 10 CFR 50.54(a) and will become effective, contingent upon NRC approval, as prescribed by the regulations.

The inspector also reviewed selected Nuclear Oversight reports covering Nuclear Oversight Verification Plan (NOVP) reviews of RFO6 and engineering activities during June 1999. The inspector held discussions on June 17 with the Station Director, Nuclear Oversight and Unit 3 Operations representatives, regarding the control of RFO6 work activities and configuration management concerns. These issues were documented in greater detail in IR 50-423/99-06. During this inspection, the inspector reviewed Surveillance MP3-P-99-013 (NOVP - Millstone Unit 3), which documents performance assessments and areas for improvement in outage planning, shutdown risk controls, configuration management, design control and modification processes, and corrective actions. This NOVP evaluation is based upon several Nuclear Oversight inspector/auditor field observations of numerous RFO6 work activities.

Functional areas within the unit that Nuclear Oversight has determined to merit further tracking for progress are consistent with NRC inspection results.

U3 O8 Miscellaneous Operations Issues (92700 & 90712)

O8.1 (Closed) LER 50-423/97-063-01: "Inadequate Operator Response Time for Inadvertent Safety Injection (SI) Event" (92700)

NRC inspection of the corrective actions associated with LER 97-063-00, regarding the same subject, was conducted and documented in inspection report (IR) 50-423/98-216, at which time this LER was closed. Supplement 1 to the original LER was issued by the licensee on June 3, 1998. In the supplement, the causal factors for this event were discussed and the corrective action commitments were revised. During the current inspection, the inspector reviewed the supplemented information and spot-checked the corrective measure completion and compliance with the revised surveillance requirements.

On June 5, 1998, the NRC issued Amendment No. 161 to the operating license for Millstone Unit 3, in the form of changes to Technical Specification (TS) 3/4.4.4. This amendment recognizes the capability of the power operated relief valves (PORVs) to perform a pressure relief function, even when isolated by block valved closure, based upon operator action to initiate quick access to the PORVs for pressure control. Since the PORVs and associated piping have been demonstrated to be qualified for water relief, their use for pressure control, either in automatic or manual actuation, precludes challenges to the pressurizer code safety valves, whose function could be adversely challenged by water relief.

The inspector reviewed the revised surveillance requirements associated with TS 4.4.4.1 and verified through interviews and record reviews that the relief valve surveillances had been and are being performed at the required periodicity. The inspector also confirmed that the emergency operating procedure (EOP 35E-0) for Reactor Trip or Safety Injection directs the operators to open at least one PORV block valve sufficiently early during any inadvertent SI event to ensure an adequate pressure relief path prior to any challenge to the pressurizer safety valves.

LER 97-063, along with supplement 1, documents a licensee identified and reported condition that potentially placed the unit in a condition outside the design basis of the plant, based upon the questioned ability to terminate inadvertent SI conditions, as described in the Unit 3 Final Safety Analysis Report. The corrective actions documented in LER 97-063-01 have been verified to be complete. Ongoing, periodic surveillance activities for the PORVs, relative to this LER, have been performed and confirmed to be up to date and appropriately controlled. **LER 50-423/97-063-01 is hereby closed.**

O8.2 (Closed) LER 50-423/98-008: "RSS Historically Outside of Design Basis as a Result of a Design Change" (90712)

As documented in NRC inspection report (IR) 50-423/98-207, a summary review of the Recirculation Spray System (RSS) design issues and corrective actions was performed by NRC. This inspection represented the culmination of NRC inspection activities from seven previous inspection periods and resulted in the closure of two escalated enforcement items (EEIs) and, correspondingly, the closure of two significant items list (SIL) issues involving the RSS design. As part of the IR closure documentation, it was recognized that a potential unreviewed safety question (USQ) had existed in the operation of the RSS, as a result of a modification effected in 1986, which resulted in the elimination of RSS direct injection into the reactor coolant system.

On February 3, 1998, the NRC issued a letter to the licensee indicating, with respect to this 1986 modification, that, "this information leads the staff to a preliminary conclusion that the modification may have involved an unreviewed safety question and, as such, may result in the need for license amendment request." On February 10, 1998, the licensee further reviewed this issue and determined that a USQ did exist, and that it had not been previously reviewed and approved by the NRC. LER 98-008 was issued by the license on March 9, 1998, to document this finding. In conjunction with this USQ determination, the licensee submitted a license amendment request on March 3, 1998, and supplemented it on May 7, 1998, which supported the elimination of the requirement to have the RSS directly inject into the reactor coolant system following a design-basis accident. The need for such direct injection was determined to remain a requirement in the case of certain long-term passive component failure scenarios, for which the licensee indicated that the Emergency Operating Procedures could provide for direct RSS cold leg injection as a contingency action.

On January 20, 1999, NRC issued Amendment No. 165 to the Unit 3 operating license, approving the licensee's integrated safety assessment and the RSS design changes pursuant to 10 CFR 50.59. The subject amendment to the Unit 3 FSAR authorizes the elimination of RSS direct injection to the reactor coolant system upon design-basis LOCA scenarios, except those involving long-term passive failures, which would be handled as EOP contingency actions. In the published NRC Safety Evaluation, the acceptability of the licensee action is based in part upon the NRC staff's conclusion documented in IR 50-423/98-207, at which time the SIL items involving the RSS were finally closed.

Based upon the activities noted above, the corrective actions documented in this LER have been completed and the current operation of the RSS is in compliance with a revised design basis that has been reviewed and approved by the NRC. As documented in IR 50-423/98-207, enforcement discretion was exercised pursuant to the NRC Enforcement Policy for both EEIs relevant to the RSS design concerns; one of which (EEI 97-202-09) identified the operation of the system outside its design basis as a result of historical design errors. The subject of this LER is similarly enveloped by historical design concerns, as is discussed in IR 50-423/98-207, at which time the EEIs involving RSS were closed with no NOVs issued. Therefore, based upon the licensee corrective

measures, NRC review, and analysis of the historical nature of the licensee problems with processing the identified USQ, **LER 50-423/98-008** is hereby **closed**.

O8.3 (Closed) LER 50-423/98-022: "Failure to Provide Required Operable Reactor Coolant System Loops in Mode 4" (90712)

The violation of TS 3.4.1.3 documented in this LER was identified by the licensee during the period of time NRC inspectors were conducting extended observations of Unit 3 operational activities in conjunction with the Operational Safety Team Inspection (OSTI), documented in IR 50-423/97-83. A notice of violation (NOV 50-423/97-83-02) was issued with the OSTI findings, for which the licensee submitted competed corrective actions in a reply to the NOV, dated July 13, 1998. These corrective actions were reviewed by a NRC inspector, resulting in the documentation of closure of this violation in IR 50-423/98-05.

During this current inspection, the inspector reviewed the corrective actions documented in LER 98-022 and found them consistent with those taken by the licensee in response to the NRC Notice of Violation. Since a prior inspection has evaluated the adequacy of the documented corrective actions, no additional review or inspection is deemed necessary. Enforcement action with respect to the identified technical specification violation has already been taken in the form of the Severity Level IV violation (97-83-02), which had been previously issued, inspected, and closed. Therefore, **LER 50-423/98-022** is hereby also considered to be **closed**.

U3.II Maintenance

U3 M1 Conduct of Maintenance

M1.1 Assessment of Ongoing Maintenance Activities

a. Inspection Scope (62707)

The inspector observed maintenance planning meetings, inspected work in progress and completed field maintenance, and reviewed procedures and other work control documents to evaluate the performance of selected maintenance activities, including emergent work that was prioritized by the licensee for completion. Work observations were chosen for review based upon plant conditions and status, the risk and safety significance of the system being worked, and the opportunity to witness maintenance in progress.

b. Observations and Findings

The inspector interviewed licensee management, work control coordinators, and craft in the field regarding the work control program, work priorities, and support for and coordination of the ongoing maintenance. The inspector noted good coordination between work control, operations, and maintenance personnel in deferring work that represented unacceptable system configurations from a risk perspective and/or

accelerating the work schedule for emergent corrective repairs necessary to restore safety-related components to operable status. During the observation of ongoing field work, the inspector reviewed the automated work order (AWO) packages, evaluated foreign material exclusion (FME) controls, and checked equipment and replacement part material conditions, as appropriate. Field inspections of some of the observed work activities are documented below:

- The inspector observed corrective maintenance on the station blackout (SBO) diesel generator air compressor. Upon noting that the air compressor was seized and inoperable, the licensee initiated corrective measures to charge the two SBO starting air receiver tanks with sufficient air from a portable source to allow for SBO diesel generator availability upon any required start demand. The repair work was appropriately controlled by four separate AWOs; one for troubleshooting and replacement of two seized compressor unloader valves, one each for the two check valves in the air line from the compressor into each receiver, and one for opening and inspecting the two air receiver tanks. Troubleshooting activities were deliberate and worked on day, swing, and mid-shifts until the repairs were effected. The inspector checked component tagging before the work started and after it was completed, confirming adequate controls. A problem with check valve chatter after restoration of the air compressor was documented by the licensee in a condition report. The inspector discussed this problem with cognizant licensee maintenance personnel, who indicated that a design change for the type of check valves installed was being pursued.

- The inspector observed maintenance and surveillance activities on the Unit 3 "B" emergency diesel generator (EDG). Specifically, the replacement of the No. 6 cylinder rocker box cover gasket, and a loop calibration on the EDG rocker arm lube oil pressure switch were witnessed. Overall, the maintenance and surveillance activities were conducted satisfactorily; however, the inspector identified minor process deficiencies during both activities. As a result, the appropriate licensee management was notified and proper action was taken by the licensee to resolve the identified deficiencies, involving some questions regarding electrical safety guidance and the status and sequence of instructions in the AWO work package.

- The inspector conducted an inspection-tour of the train "A" service water (SWP) pump room inside the intake structure, examining material conditions, equipment tagging, and operating and standby pump status. Subsequent inspection confirmed acceptable throttled valve positioning for specific SWP valves in accordance with an operations valve lineup verification (Ops Form 3626.1-1). The inspector also discussed with the responsible system engineer the operating strategy for the SWP system, as it is documented in an engineering procedure, EN 31084. The conduct of the required train "A" SWP internal piping inspection during RFO6 was verified; and the conduct documentation, and trending of other periodic SWP system inspections of heat exchangers, in accordance with Generic Letter 89-13 and other programmatic commitments, were discussed with the system engineer. The inspector also reviewed EN 31084 (Revision 3)

through change No. 6, and noted adequate guidance for inspections, data collection, and criteria to identify and correct system fouling. Implementation of this procedurally controlled operating strategy ensured continued operability of both trains of the SWP system.

c. Conclusions

Overall, the inspection of selected Unit 3 maintenance activities, including field observations, document reviews, and work controls and priorities, identified acceptable practices and good coordination across the unit departments. The prioritization and authorization for off-shift work hours to complete safety-related and risk significant equipment work, and repair activities requiring entry into a technical specification action statement were well controlled. Good coordination of the daily work to minimize plant risk was evident. Preventive maintenance inspections and other work were well planned and procedurally controlled. In the case of reviewed service water system activities, the system engineer appropriately implemented an operating strategy for monitoring and trending equipment conditions.

M1.2 Surveillance Observations

a. Inspection Scope (61726)

The inspector observed portions of selected surveillance activities to confirm compliance with applicable technical specifications and procedures. Systems were selected based on their risk significance. The inspector also reviewed selected test results to confirm appropriate operability designation.

b. Observations and Findings

Portions of the following surveillances were observed:

- SP 3646A.8 Slave Relay Testing - Train A
- SP 3630A Reactor Plant Component Cooling Water Pump (CCP) 3CCP*P1A Operational Readiness Test

The pre-job briefings for the observed surveillances adequately covered the precautions, expected outcomes, and potential problems. The means of communication between control room and in-plant personnel were discussed and implemented satisfactorily. The shift manager also stressed that there was no time pressure to complete the surveillance.

With the warmer weather experienced this summer, the inspector noted an appropriate discussion of the effect of isolating the main steam valve building ventilation during the CCP operational test. No impact was expected because the system was to be isolated for a short period of time. The inspector observed the high temperature alarm come in before the testing was started, as was not uncommon this season.

Overall, the surveillances were performed in a deliberate and controlled manner in accordance with the approved procedures. However, the inspector did observe an instance during the slave relay testing where the procedure required independent verification (IV) of the installation of a volt meter. During the installation, the step was peer checked (not required by procedure), but upon noting the step required verification, the instrument and control (I&C) technician who did the peer check initially signed off for the IV. The control room operator performing the test initially verified the step was signed and prepared to proceed with the procedure. At this point, the inspector questioned the conduct of the IV activity. To meet the requirement, the shift technical advisor then performed the IV. The inspector observed proper verifications throughout the rest of the surveillance. Subsequent to the testing the I&C technician and operator discussed the IV issue with the unit supervisor. Since other similar testing requires a dual versus independent verification for similar steps, the plant personnel decided to submit a procedure change. Although changing the procedure requirement may be appropriate, there was an observed lack of attention to detail during the surveillance. This NRC-identified procedural non-compliance was of minor safety significance, and per the NRC Enforcement Policy will not be cited.

The inspector reviewed the completed data sheets for selected surveillances and confirmed that the data matched what was observed in the field and all acceptance criteria were met. Systems were properly restored to an operable condition following testing activities.

c. Conclusions

Observed Unit 3 surveillance activities were generally performed in a controlled manner in accordance with approved procedures. One instance of inattention to detail was observed by the inspector regarding improper independent verification. The error was corrected and did not recur through the rest of the surveillance.

M1.3 Maintenance Rule Implementation on Selected Systems

a. Inspection Scope (62707)

The inspector selected three Unit 3 risk significant systems for review with respect to implementation of the maintenance rule. Associated system scoping information, unreliability data, second quarter system engineer quarterly reports, and applicable a(1) system action plans were reviewed and compared to the licensee's applicable maintenance rule implementing procedures to ensure proper implementation of the rule.

b. Observations and Findings

The implementation of the maintenance rule with respect to the service water (SW) system, auxiliary feedwater (AFW) system, and containment recirculation spray (RSS) system was evaluated. The original performance criteria for all three systems was adequate and unreliability data was appropriately tracked. The AFW and SW systems were properly classified as a(1) systems. Associated approved action plans included

appropriate goals and monitoring requirements with due consideration of industry experience.

The inspector noted that incomplete maintenance rule action requests are discussed twice a month during the director/manager morning meetings to ensure proper attention and resources are focused on a(1) systems.

c. Conclusions

The maintenance rule was properly implemented on the Unit 3 risk significant service water, auxiliary feedwater, and containment recirculation spray systems. Scoping information, performance criteria and unreliability data were maintained in accordance with approved procedures. Maintenance rule action plans were in place for the applicable systems and their status and unavailability were monitored by licensee management.

U3 M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Licensee Event Report (LER) 50-423/99-003-00: Inadequate 18 Monthly Surveillance Test On The Emergency Diesel Generators.

On May 5, 1999, the licensee discovered that since May of 1995, a required technical specification (TS) surveillance test on the emergency diesel generators (EDGs) had not been performed. Specifically, TS surveillance 4.8.1.1.2.g.6.b required, in part, that each diesel generator shall be demonstrated OPERABLE at least once every 18 months, by simulating a loss-of-offsite power in conjunction with an Engineered Safety Feature (ESF) Actuation test signal, and verifying that the diesel starts from standby conditions.

The inspector determined that the licensee initiated prompt action by declaring both EDGs inoperable, subsequently performed the required surveillance tests, placed the violation in the corrective action program, initiated a root cause evaluation, and instituted appropriate immediate and compensatory corrective actions. In general, a major causal factor of the missed surveillance was the failure to incorporate the necessary changes into the required surveillance test when a 1995 license amendment was issued. Subsequently, the licensee had initiated the loss of power and emergency safeguard actuation tests from a "hot" condition following a 24 hour endurance run that satisfied another TS requirement, and not from the "standby" condition required by TS 4.8.1.1.2.g.b.

As a result, the licensee had failed to verify that each diesel started from standby conditions since May 1995, and this is considered a violation of NRC requirements. Based upon the licensee's corrective actions, promptly initiated upon problem discovery, this Severity Level IV violation is being treated as a Non-Cited Violation (NCV 50-423/99-08-11), consistent with Appendix C of the NRC Enforcement Policy. This violation is currently in the licensee's corrective action program as condition report M3-99-1399; LER 50-423/99-003-00 is considered closed.

M8.2 (Closed) LER 50-423/98-018-00: Limiting Condition for Operation Action not Completed Within Specified Time Limit.

On March 2, 1998, the licensee identified that the noble gas grab sample time of 12 hours for technical specification (TS) limiting condition for operation (LCO) 3.3.3.10, Table 3.3-13, Item 2.a., Action 37, was exceeded by five minutes. The grab samples were initiated due to the Unit 1 Main Stack Noble Gas Activity Monitor being declared inoperable on February 11, 1998, as detailed in LER 50-423/98-010-00, and documented in NRC Inspection Report 50-423/99-06 dated July 9, 1999. The violation occurred due to an inappropriate application of a 25% grace period to a TS-required action, whereas this grace period normally applies to the performance intervals of TS surveillance activities.

The inspector determined that the licensee had completed appropriate corrective actions, including: (1) initiation of a root cause evaluation, which identified inadequate administrative controls regarding TS requirements shared among the three units as the root cause, (2) completion of a comprehensive review of non-Unit 3 surveillance procedures that satisfy TS requirements to ensure compliance, (3) revision of the affected procedures to clarify the application of the 25% grace period, and (4) placement of this issue in the site corrective action program.

While the safety significance of this TS violation is minimal due to the relative short time period involved and since the main stack continued to be monitored, the failure to complete the noble gas grab sample within the required time is considered a violation of NRC requirements. This Severity Level IV violation is being treated as a Non-Cited Violation (**NCV 50-423/99-08-12**), consistent with Appendix C of the NRC Enforcement Policy. This violation is currently in the licensee's corrective action program as condition report M3-98-1194; **LER 50-423/98-18-00** is considered **closed**.

U3.III Engineering

U3 E1 Conduct of Engineering

E1.1 Review of Ongoing Engineering Activities

a. Inspection Scope (37551, 92903)

The inspector evaluated ongoing engineering activities, including those initiated in response to emergent equipment issues with both operational and design-basis implications. The inspector interviewed the cognizant system engineers, design engineers, operations and maintenance staff, and supervisors to assess the level of coordination being effected to resolve identified problems. Condition reports, safety evaluations, and plant modifications were reviewed, as appropriate, to check both the status and completeness of the licensee's engineering work, which continued in progress through the end of this inspection period

b. Observations and Findings

Specifically, the inspector reviewed engineering activities related to the following technical issues:

- Follow-up of the high energy line break (HELB) concerns raised with respect to normal ingress/egress through control room access door, C-49-1; as was documented in NRC IR 50-423/99-05: The inspector reviewed the safety evaluation and supporting material for a minor modification (MMOD M3-99022) of the HELB design basis for a main steam line break in the turbine building. Work on the design for an additional HELB vestibule outside of door C49-1 (i.e., MMOD M3-99023) commenced, but physical work for this modification was deferred until after the completion of RFO6. The inspector reviewed preliminary drawings for the control room HELB door vestibule and examined the work area where the pre-staging of materials and construction equipment had begun. This modification is expected to be completed during the next inspection report period.

- Follow-up of the engineering changes and implementation status of the special procedure (SPROC EN98-3-17) for monitoring the gas accumulation in the gravity feed boration lines: The inspector verified the plant design requirements for safety grade cold shutdown capabilities require gas volume measurements to be conducted once per week, and under other specific operating conditions, while the unit is in operational Modes 1 through 3. The inspector noted that a SPROC change eliminated the need for such measurements in shutdown Modes 4 through 6, unless the gravity boration flow path is credited to meet TS requirements. The inspector reviewed the TS surveillance for the boration flow path verification in Modes 4 - 6, but found no reference to the SPROC.

  While this omission does not represent a problem when the emergency boration flowpath or suction lines from the refueling water storage tank are available, the inspector noted that when gravity boration is required as the credited TS flowpath, it would not be immediately known if the flowpath is operable unless the SPROC is performed. The inspector discussed this apparent discrepancy with the system engineer and operations support engineer. The inspector also identified some other inconsistencies in the performance of the monthly TS surveillance procedure, SP 3604C.2. These items were minor editorial issues, which the licensee documented in CR M3-99-2867 for further review and revision.

  Since system modifications to eliminate the gas accumulation in the gravity boration lines were still under evaluation by the licensee, LER 50-423/98-016 with supplements 1 & 2, remain open to address final corrective action. With Unit 3 currently in Mode 1, the inspector confirmed that the SPROC EN-98-3-17 provisions were being adequately performed. Licensee actions to address the potential discrepancy between the SPROC and the surveillance requirements in Modes 4 - 6 will be reviewed as part of the final inspection closure for LER 98-016.

- Follow-up of the engineering impact and design-basis applicability of leaking steam generator atmospheric dump valves (3MSS*PV20A-D): The inspector questioned why no stroke closure time was listed in the Unit 3 FSAR, since these valves receive a steam line isolation (SLI) signal. Discussion with an engineer in the licensee's safety analysis group revealed that the valves had no containment isolation stroke-closure time because of the "closed loop" design of the main steam/ steam generator piping penetrating containment. The inspector reviewed the revised steam generator tube rupture analysis submitted to the NRC by the licensee in 1998, along with a Westinghouse evaluation of the FSAR Chapter 15 steamline break accident analysis and a licensee evaluation of the SLI signals to the 3MSS*PV20 valves, and determined that a failed-open 3MSS*PV20 valve is conservatively bounded by the main steam line break accident analysis. Additionally, based upon credible steam line break scenarios, the inspector confirmed that the licensee had qualified the atmospheric relief isolation valves, 3MSS*MOV18A-D, in accordance with the electrical equipment qualification (EEQ) program, as prescribed by design change record, DCR M3-98005. Closure of the corresponding MOV18 valve isolates a PV20 valve leak, as was implemented to repair the PV20B valve discussed below.

  Since the inspector noted that the 3MSS*PV20B was leaking considerably more than the other three atmospheric dump valves, the inspector also questioned whether such a leak adversely affected the analyzed SLI signal. Licensee engineering review with Westinghouse revealed that the low steam line pressure setpoint has considerable margin because of environmental effects inside containment. Since the PV20B valve is outside containment and was noted to be leaking at a rate considerably lower than that required for a SLI, this concern also appeared to be bounded by the plant accident analysis. Subsequently, the licensee effected repairs to reseat the 3MSS*PV20B valve, substantially reducing the leakage rate. The inspector verified that during periods of subsequent testing, with the 3MSS*PV20B valve inoperable, the corresponding isolation valve, 3MSS*MOV18B was appropriately closed and the corresponding limiting condition for operation, TS 3.7.1.6, entered and tracked until valve operability was restored.

c. Conclusions

The review of ongoing Unit 3 engineering activities, conducted as follow-up to known system or equipment problems, revealed adequate design implementation, within the assumed accident analysis and other design-basis considerations. Where commitments had been made by the licensee to address specific design concerns (e.g., component EEQ for steam line breaks; piping configuration analyses to review gas accumulation; HELB assumptions), the inspector verified that the licensee implemented the appropriate actions to further evaluate the identified issues.

E1.2 Year 2000 Project Readiness Review

Please refer to Section U2.E1.3 of this report for a discussion of this area.

IV Plant Support
(Common to Unit 1, Unit 2, and Unit 3)

R1 Radiological Protection and Chemistry Controls

R1.1 (Open) URI 50-423/99-08-13: 7.04 rem TLD Exposure Event

a. Inspection Scope (83724)

On July 8, 1999, during routine second quarter personnel thermoluminescent dosimetry (TLD) processing, a TLD belonging to an I&C technician indicated 7.04 rem. Subsequently, the Millstone radiation protection organization informed the NRC that they had initiated an investigation of the matter to determined the cause of the exposure. The inspector performed an independent review and evaluation of the licensee's event review effort by examining pertinent records and documents, reviewing radiological controls, interviewing personnel, and physically examining work locations and radioactive source devices to which the individual had access.

b. Observations and Findings

The licensee was continuing extensive and comprehensive efforts to understand the cause of the exposure to the individual's TLD. The licensee concluded that the exposure to the badge was actual, but believes that the available information and evidence suggests that the individual did not actually receive a 7.04 rem exposure. This assessment was based an a comprehensive collection and analysis of pertinent information and records, including the recorded readout of electronic dosimetry devices that were worn by the individual when accessing the radiological control areas of the plant, applicable procedures and access control processes, interviews with cognizant personnel, time and motion studies of the individual's work and practices, and pertinent radiological control and work records. A comprehensive review of possible abnormalities with the TLD was also conducted by the licensee, including tests of possible anomalies and other sources that could be responsible for the exposure.

While not a regulatory requirement, the licensee, as a normal practice, does not exercise positive control of individuals' TLDs, even though the device is regarded as the primary device to estimate and monitor personnel exposure for regulatory purposes. Individuals were allowed to control their own devices, including storing it in unsecured locations, taking it home with them, or keeping it in their desks or lockers. Accordingly, in these circumstances, the individual's TLD device was not secured or controlled in a manner that would have prevented tampering with, or deliberate exposure of, the TLD. Accordingly, as part of the event review effort, the licensee initiated a formal investigation by the corporate investigations organization in an effort to establish the cause of the

exposure. The event was also documented in the licensee's problem identification and corrective action system as condition report (CR) M3-99-2642. Pending completion of the review, the licensee has restricted the affected individual from entering Radiologically Controlled Areas, or performing radiological work. This matter is considered unresolved pending the licensee's completion of the event review and investigation effort. **(URI 50-423/99-08-12)**

c. Conclusion

The licensee is continuing to conduct an aggressive and comprehensive event review of a 7.04 rem exposure, involving an individual's personnel TLD device, to determine if the exposure represents an actual exposure to an individual or was the result of tampering with the individual's TLD, or other deliberate misconduct. The licensee's event review effort was conducted by knowledgeable personnel, and was comprehensive in scope and depth.

R1.2 Internal Exposure Program Review With Respect To Transuranics

a. Inspection Scope (83725)

The inspection consisted of a review of the licensee's current transuranic characterization of the workplace, the alpha radiation detection capabilities and internal exposure assessment procedures. Applicable documents were reviewed and cognizant radiation protection staff members were interviewed.

b. Observations and Findings

The licensee has established an effective control and monitoring program for internal personnel exposure. Through July 1999, there have been no recorded internal exposures for personnel at Millstone station due to excellent contamination control practices. Notwithstanding, the inspector observed that the parameters established for alpha counting of air samples achieved a minimum detectable concentration of 9E-13 uCi/cc. For unidentified alpha-emitting radionuclides at Millstone, the alpha DAC is 3E-12 uCi/cc. The posting of airborne radioactive areas is established at 0.3 DAC, which is the same as the minimum detectable concentration of 9E-13 uCi/cc. The licensee's procedure, RPM 2.10.2, Rev. 6, "Air Sample Counting and Analysis," specifies $\leq$ 0.1 DAC counting level for determining a radionuclide is not present, which is not consistent with the 0.3 DAC minimum detectable concentration that is used in practice for the alpha counting. Since the licensee's normal radiological controls have been successful in preventing any internal uptakes, there is no immediate safety significance to this observation. Notwithstanding, the licensee initiated action to re-evaluate the current alpha counting sensitivity and make any necessary procedure changes.

c. Conclusions

While transuranic activity is present in the source term of all Millstone units, the licensee has established excellent contamination control practices that have successfully

prevented internal exposure to personnel. Notwithstanding, the licensee has initiated actions to re-evaluate current alpha monitoring sensitivity and practices to improve personnel exposure control to transuranic activity.

R1.3 Miscellaneous Liquid Radwaste Equipment Status

a. Inspection Scope (84723)

Several liquid radwaste equipment issues were reviewed. In Unit 1, the 'A' train of the floor drain system and the spent resin tank discharge system were unavailable in December 1998. In Unit 2, for final water polishing, there is only one secondary demineralizer as designed. This limitation was reviewed against FSAR commitments. In Unit 3, the waste monitor and boron recovery tank leakage path had been isolated from the storm drain system by installation of a temporary asphalt berm in January 1999. Permanent commitments were reviewed. The Unit 1 and Unit 3 issues consisted of onsite interviews and the review of licensee documents. The Unit 2 issue consisted of an in-office review of documents and telephone interviews of licensee personnel.

b. Observations and Findings

The Unit 1 'A' floor drain liquid radwaste system had experienced through-wall cracking and a valve (LRF63) had been previously removed rendering the system inoperable. During the inspection, replacement of the LRF63 valve and associated piping was in progress and expected to be complete in August 1999 rendering the 'A' floor drain system operable. The spent resin tank discharge system consisted of hose jumpers and a positive displacement pump for discharging into a shipping liner. In 1998, the hoses were determined to be below the required pressure rating for this operation and were declared inoperable. Cognizant personnel confirmed that the condition is recognized and indicated that sufficiently rated hoses would be installed, if and when spent resin is required to be discharged and shipped for reprocessing or disposal.

The Unit 2 final water polishing through a single secondary demineralizer was reviewed with respect to FSAR design basis throughput criteria as specified in Section 11.1 of the Unit 2 FSAR. The inspector reviewed past Annual Effluent Release Reports, and spoke with the Unit 2 Liquid Radwaste Plant Equipment Operator and the Unit 2 Radwaste System Engineer. With respect to the Unit 2 Clean Liquid Radwaste processing system, after excess reactor coolant is automatically filtered and demineralized, water accumulates in one of two 60,000 gallon capacity receiver tanks. After sampling and characterizing, the water may be batch processed through a single secondary demineralizer and collected in one of two 30,000 gallon capacity monitor tanks. Final sampling and dilution calculations are made prior to releasing the water to the quarry and out to Long Island Sound. The availability of the single secondary demineralizer may be considered a system limitation. Another secondary system limitation is with regard to a radioactivity concentration in a sampled waste monitor tank. In this condition, the water would normally be recycled through the secondary demineralizer and would require the other waste monitor tank for collection and sampling. If one of the waste monitor tanks were not available, then the water would be recycled back to the waste receiver tanks, to

start the cycle again. Although, this condition may be considered inefficient from a water processing standpoint, it does not pose a safety problem.

Section 11.1 of the FSAR describes the design basis of the liquid radwaste system as being capable of processing maximum design quantities of wastes (840,000 gallons per year or 1.6 gpm average), with 1% failed fuel and steam generator primary-to-secondary leakage of 432 gallons per day (or 0.3 gpm). The combined maximum waste water and steam generator leakage rates equate to 1.9 gpm. The secondary demineralizer processes water at 15 gpm, which is above the rates specified in the FSAR. As mentioned previously, if the secondary demineralizer or associated waste monitor tanks are out of service, then waste water may be delayed in being released and may require storage until processing capacity is restored.

A review of Unit 2 liquid effluent release performance was conducted. Over the past four years (1995-1998), the maximum quarterly dose reported was 7.62E-3 mrem per quarter to the maximum individual (0.5% of TS limit) and 4.83E-2 mrem per quarter to the maximum organ (1% of TS limit). With respect to 10 CFR 50, Appendix I, during the same four years, the maximum annual doses were 0.4% and 0.6% of the whole body and organ dose limits. From 1995 to 1998, Millstone Unit 2 has performed liquid effluent releases that were As Low As is Reasonably Achievable (ALARA).

In Unit 3, on January 4, 1999, leakage from a small bore pipe gasket associated with the A3 waste test tank resulted in approximately 1050 gallons of processed water being unintentionally released into the Niantic Bay via the storm drain system. Subsequent corrective actions included erection of a temporary asphalt berm to contain any future equipment leakage events. Unresolved item number 50-423/98-06-02 was initiated pending final licensee corrective actions to resolve this issue. At the time of this inspection, preliminary plans for a concrete berm to surround the 4 tanks had been developed and funding for the project had been committed with construction to be completed by the end of 1999. As documented in IR 50-423/99-07, since this issue has been placed in the licensee's corrective action program, URI 50-423/98-06-02 is confirmed closed.

c. Conclusions

Several liquid radwaste equipment issues were reviewed, but no safety or regulatory concerns were identified. Repair of the Unit 1 'A' floor drain system was underway and expected to be complete in August 199, restoring the system to operability. The Unit 2 final liquid polishing system was found to reflect its design commitments in the FSAR and past effluent releases have been ALARA. Funding was provided for the construction of a leakage retention concrete berm around the Unit 3 waste test tanks and the Unit 3 boron recovery tank.

R1.4 Miscellaneous Radiation Control Issues

a. Inspection Scope (83724)

Review of the use of departmental ALARA goals and the definition of high radiation area in Technical Specifications 6.12.1 and 6.12.2 was conducted through onsite interviews.

b. Observations and Findings

The Unit 2 ALARA Coordinator indicated that during the past several years of forced outage, ALARA goals were frequently changed in order to follow the frequently changing emergent outage work activities. The ALARA coordinator indicated that since Unit 2 has returned to normal plant operations, there should not be ALARA goal changes once annual and refueling outage goals are established. The Unit 3 ALARA Coordinator indicated that once ALARA goals are established they are not changed. In no case have individual personnel exposure records been changed or altered due to ALARA goal revisions.

Before 10 CFR 20 was revised (effective January 1, 1994), a high radiation area was defined as an accessible area where a major portion of the body could receive a dose in excess of 100 mrem in one hour. After 10 CFR 20 was revised, the definition was clarified to indicate a distance from the source at 30 centimeters. The Millstone Unit 2 and Unit 3 Technical Specifications 6.12.1 and 6.12.2 define a high radiation area and a locked high radiation area at a distance of 45 centimeters. A review of licensee procedures indicates that the current 10 CFR 20 definition of 30 centimeters has been incorporated into the RP program. The licensee indicated that the subject technical specifications would be changed to agree with 10 CFR 20.

c. Conclusions

The Millstone Unit 2 and Unit 3 Technical Specification 6.12.1 and 6.12.2 definitions of high radiation areas are not consistent with 10 CFR 20 and will be revised by the licensee. Program adherence to the 10 CFR 20 requirements was verified.

S6 Security Organization and Administration

a. Inspection Scope (81700)

The area inspected was staffing levels.

b. Observations and Findings

Review of staffing levels for the security organization disclosed that as a result of a turnover rate of approximately 20% for the first half of the year in the sergeant ranks, there was a chronic shortage of sergeants to man regulatory required posts. This shortage resulted in the remaining sergeants having to work overtime, often with little notice, to man the posts. The overtime burden was resulting in morale problems in the

sergeant ranks and appeared to be contributing to the acceleration of the turnover rate. Discussions with licensee security management disclosed that they were aware of the problem and some new sergeants were in the training and qualification process. Further discussion disclosed that because there were a limited number of new sergeants being trained, and as a result of the time required to train the new sergeants, the problem was not going to be solved in the near term. The licensee agreed that a more proactive approach was needed and decided to aggressively address the problem. An action plan was developed that included new temporary staffing criteria, the addition of temporary contingency staffing positions and the upgrading of a technician to the supervisory ranks.

c. Conclusions

The staffing levels in the sergeant ranks were adequate to man all required posts and the overtime worked was within prescribed limits, however, chronic shortages in the ranks were resulting in the sergeants working more overtime than desired, which contributed to a morale problem. Licensee security management has developed an action plan to address the issue of the chronic shortages in staffing and reduce overtime.

S8 Miscellaneous Security and Safeguards Issues

a. Inspection Scope (81700)

The area inspected was fitness-for-duty (FFD) program implementation.

b. Observations and Findings

Review of the licensee's FFD program including the testing process, the chain-of-custody process and the appeal process disclosed the following:

- The testing process was completed in accordance with licensee procedures and regulatory requirements. There were minor administrative errors identified on several forms. The administrative errors have been addressed in the licensee's corrective action program and have been corrected. The administrative errors did not compromise the validity of the testing process.

- The chain-of-custody process was implemented in accordance with licensee procedures and regulatory requirements. There were also minor administrative errors in the chain-of-custody process that have been addressed in the licensee's corrective action process. The inspectors reviewed the licensee's FFD permanent record book and other chain-of-custody source documentation to verify that the minor administrative errors did not compromise the chain-of-custody process.

- The appeal process was reviewed and determined to be in accordance with regulatory requirements. The licensee did identify in an internal audit that the MRO had not completed a recertification process within five years. The recertification process for MROs is not a regulatory requirement, however, when

this failure to recertify was identified, the MRO did complete the recertification process.

c. Conclusions

The licensee's fitness for duty (FFD) program, as implemented, met regulatory requirements. Through internal audits and other means, minor administrative errors have been identified in the program and the errors have been addressed in the licensee's corrective action program. None of the administrative errors identified had a negative impact on the validity of the FFD program and none of the errors was sufficient to overturn or question the results of an FFD test.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection period. The licensee acknowledged the findings presented.

INSPECTION PROCEDURES USED

TI 2515/141	Review of Year 2000 (Y2K) Readiness of Computer Systems at Nuclear Power Plants
IP 37551	Onsite Engineering
IP 40500	Licensee Self-Assessments Related to Safety Issues Inspections
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71707	Plant Operations
IP 81700	Physical Security Program for Power Reactors
IP 83724	External Occupational Exposure Control and Personal Dosimetry
IP 83725	Internal Exposure Control and Assessment
IP 84723	Liquids and Liquid Wastes
IP 90712	In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92700	Onsite follow-up of Written reports of Nonroutine Events at Power Reactor Facilities
IP 92703	Followup of Confirmatory Action Letters
IP 92901	Followup - Plant Operations
IP 92902	Follow-up - Maintenance
IP 92903	Follow-up - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-336/99-08-01	NCV	Failure to Promptly Address Potential Air Entrapment in the Emergency Core Cooling System
50-336/99-08-02	NCV	Failure to Initiate a Condition Report when a Leakage SI Accumulator Isolation Valve was Identified
50-336/99-08-03	NCV	Inadequate Troubleshooting Procedure for the "A" Emergency Diesel Generator Related to LER 50-336/97-027-00
50-336/99-08-04	NCV	Failure to Meet ASME Section XI Surveillance Requirements Related to LER 50-336/97-024-00 &-01
50-336/99-08-05	NCV	Failure to Promptly Address Water Intrusion into "B" Auxiliary Feedwater Pump Bearing
50-336/99-08-06	NCV	Failure to Write a Condition Report for an Unanalyzed Flow Distribution in the RBCCW System
50-336/99-08-07	NCV	Failure to Control Parts Used in the Reactor Protection System Related to LER 50-336/97-021-00
50-336/99-08-08	NCV	Failure to Identify Single Failure Vulnerability in the Auxiliary Feedwater System Water Supply Related to LER 50-336/97-025-00
50-336/99-08-09	NCV	Inadequate Design of the 120 Volt AC Distribution System Related to LER 50-336/98-001-00
50-336/99-08-10	NCV	Inadequate Main Steam Line Break Analysis Related to LER 50-336/98-007-00 &-01
50-423/99-08-11	NCV	Inadequate 18 Month Surveillance Test On The Emergency Diesel Generators
50-423/99-08-12	URI	7.04 rem TLD exposure event

Closed

The NCVs opened above are closed.

50-245/95-82-02	URI	Refueling Evolutions Contrary to Design Basis
50-245/95-82-03	EEI	Failure to Evaluate SFP Impact on SBGT System
50-245/95-82-04	EEI	VIO 01012: SFP Rerack Modifications
50-245/95-82-08	EEI	SFP Modified for Re-Racking to Hold More Control Rods
50-245/95-82-09	EEI	VIO 01182: SFPC System Modification
50-245/ 95-82-10,11,18	EEI	VIO 01032: SFP Cooling System
50-245/95-82-12	EEI	VIO 04013: SFPC System
50-245/95-82-13	URI	Verify satisfactory resolution of high flows to SDC heat exchanger
50-245/95-82-14	EEI	VIO 01022: RBCCW System
50-245/95-82-19	EEI	Switch From 1/4 TO 1/3 Fuel Core Offloads
50-245/95-82-20	EEI	Failure to Change Core Offload Status
50-245, 336, 423/ 97-85-02	URI	Training Program Deficiencies - CAL Item 8

50-245, 336, 423/ 97-85-03	URI	Establish Training Staff Prior Staff Levels
50-336/95-42-04	VIO	Intake Structure Ventilation System Deficiencies
50-336/97-208-02	URI	Nuclear Instrument Drawer Calibration
50-336/98-207-06	VIO	Failure to Implement Written Procedures for Operation of the Reactor Building Closed Cooling Water (RBCCW) System
50-336/98-207-07	VIO	Failure to Test the Four Digital Liquid and Gaseous Effluent Radiation Monitors in a Manner Consistent with Technical Specifications
50-336/98-216-01	VIO	Mispositioning of a Throttle Valve in the Reactor Building Closed Cooling Water System
50-423/98-06-02	URI	Processed water from the A3 waste test tank unintentionally released into the Niantic Bay

The following LERs were also closed during this inspection:

LER 50-336/97-021-00	Non-Quality Assurance (non-QA) Lamps Installed in the QA Category I Reactor Protection System
LER 50-336/97-024-00&01	American Society of Mechanical Engineers (ASME) Section XI Surveillance Requirements
LER 50-336/97-025-00	Condensate Storage Tank (CST) Single Failure
LER 50-336/97-027-00	Unplanned Automatic Start of the "A" Emergency Diesel Generator While Troubleshooting
LER 50-336/98-001-00	Vital 120 Volt AC System Fault Clearing Coordination
LER 50-336/98-015-00	Failure to Test the Four Digital Liquid and Gaseous Effluent Radiation Monitors in a Manner Consistent with Technical Specifications
LER 50-336/99-001-00	Failure to Perform a Required Surveillance on a Fire Door
LER 50-336/98-007-00&01	Reanalysis of Final Safety Analysis Report (FSAR) Main Steam Line Break Analysis Indicates Possible Fuel Failures
LER 50-423/97-063-01	Inadequate Operator Response Time for Inadvertent Safety Injection (SI) Event
LER 50-423/98-008	RSS Historically Outside of Design Basis as a Result of a Design Change
LER 50-423/98-022	Failure to Provide Required Operable Reactor Coolant System Loops in Mode 4
LER 50-423/99-003-00	Inadequate 18 Month Surveillance Test On The Emergency Diesel Generators
LER 50-423/98-018-00	Limiting Condition for Operation Action not Completed Within Specified Time Limit