February 1, 2000

EA No. 00-003

Mr. Stephen E. Scace, Director
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 05000336/99014 and 05000423/99014

Dear Mr. Scace:

On January 3, 2000, the NRC completed an inspection at Millstone Units 2 & 3 reactor facilities. The enclosed report presents the results of that inspection.

During the six-weeks covered by this inspection period, your conduct of activities at the Millstone facilities was generally characterized by safety-conscious operations, sound engineering and maintenance practices, and careful radiological work controls. Both units remained at power, in operational Mode 1, throughout the inspection period.

Based on the results of this inspection, the NRC identified two Level IV violations of NRC requirements, one of which related to the Unit 3 procedural violation involving the erection of scaffolding without the requisite engineering review to ensure that seismic interactions would not adversely impact the operability of nearby safety-related equipment. The other example involved a Unit 2 Maintenance Rule violation (10 CFR 50.65(a)(1)) associated with repetitive functional failures of the reactor protection system that our inspectors identified. In addition, the NRC determined that six Level IV violations of NRC requirements, which were associated with conditions that are described in Licensee Event Reports, occurred prior to 1999. All of these violations are being treated as Non-Cited Violations (NCVs), consistent with Section VII.B.1.a of the NRC Enforcement Policy. The 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. 05000336 and 05000423
License Nos. DPR-21, DPR-65, NPF-49

Enclosure: NRC Combined Inspection Report 05000336/99014 and 05000423/99014

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U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos.:	05000336	05000423
Report Nos.:	99014	99014
License Nos.:	DPR-65	NPF-49

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

Facility: Millstone Nuclear Power Station, Units 2 and 3

Inspection at: Waterford, CT

Dates: November 23, 1999 - January 3, 2000

Inspectors: D. P. Beaulieu, Senior Resident Inspector, Unit 2
A. C. Cerne, Senior Resident Inspector, Unit 3
P. C. Cataldo, Resident Inspector, Unit 1
S. R. Jones, Resident Inspector, Unit 2
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J. G. Caruso, Operations Engineer, Region I
P. R. Frechette, Security Inspector, Region I
K. M. Jenison, Senior Project Engineer, Region I
G. C. Smith, Senior Physical Security Inspector, Region 1
J. D. Wilcox, Senior Operations Engineer, NRR

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

EXECUTIVE SUMMARY
Millstone Nuclear Power Station
Combined Inspection 50-336/99-14; 50-423/99-14

Operations

- The established Unit 3 operational and radiological controls were adequate to provide for the safe implementation of plant evolutions and control room activities, as well as for the effective handling and tracking of plant equipment status. Issues involving component operability, availability, reportability, and regulatory compliance were appropriately addressed by the licensee staff. (Section U3.O1.1)

Maintenance

- At Unit 2, the overall conduct of the maintenance and surveillance activities was found acceptable. However, the NRC identified that although the on-line maintenance procedure specified that Operations Manager approval was needed when the planned removal of equipment from service placed the plant in an "Orange" risk condition, the plant staff had not been documenting his approval. Because the Operations Manager was aware of the "Orange" conditions, he had approved the conditions. Therefore, no violation occurred. The licensee's corrective action, which involved changing the on-line maintenance procedure to remove the statement regarding Operations Manager approval, was found acceptable. (Section U2.M1.1)

- At Unit 2, the licensee failed to recognize that the established performance criteria of no repetitive functional failures for the reactor protection system was exceeded on May 28, 1999, and again exceeded in October and November 1999, when another three functional failures occurred. The licensee failed to place the system into an (a)(1) status and establish goals commensurate with safety in violation of 10 CFR 50.65(a)(1). This violation is being treated as a Non-Cited Violation, consistent with section VII.B.1.a of the NRC Enforcement Policy. (NCV 50-336/99-14-01). (Section U2.M1.2)

- At Unit 2, the NRC concluded that the licensee's determination of continued operability of the reactor protection system, despite some degradation, was adequately founded. The majority of issues pose only a minimal increase in the probability of an inadvertent reactor trip or a distraction to the control operators and have no effect on the system's safety function. The licensee has implemented or scheduled appropriate measures to address the degraded conditions consistent with their importance to safety. However, the licensee was untimely in developing a plan to address recurrent instances where an RPS channel was rendered inoperable due to a drifting thermal margin/low pressure setpoint. This untimeliness related to a violation described in Section U2 M8.2, where the NRC found that the licensee failed to identify that system performance goals with respect to maintenance preventable functional failures, which were established by the licensee pursuant to 10 CFR 50.65, had not been met. (Section U2.M1.3)

- At Unit 2, the licensee identified in 1998 that the technical specification (TS) required, ASME code visual tests, had not been performed on portions of safety injection recirculation header piping. This is a violation of Unit 2 TS 4.0.5. The licensee's corrective actions were found acceptable. This violation of TS 4.0.5, is being treated as a Non-Cited Violation (NCV 50-336/99-14-02). LER 50-336/98-20-00 is closed. (Section U2.M8.3)

- At Unit 2, the licensee identified in 1998 that the technical specification (TS) required containment air recirculation fan start testing, had historically not been performed. This is a violation of TS 4.6.2.1.2. The licensee's corrective actions were found acceptable. This violation of TS 4.6.2.1.2, is being treated as a Non-Cited Violation (NCV 50-336/99-14-03). LER 50-336/98-23-00 is closed. (Section U2.M8.4)

- At Unit 2, the licensee identified in 1998 that the technical specification (TS) required check valve full flow tests had not been performed in accordance with ASME Section XI requirements, on specific check valves. This is a violation of TS 4.0.5. The licensee's corrective actions were found acceptable. This violation of TS 4.0.5, is being treated as a Non-Cited Violation (NCV 50-336/99-14-04). LER 50-336/98-25-00 is closed. (Section U2.M8.5)

- Review of the licensee's work control procedures governing the erection of scaffolding identified adequate controls and engineering directions. However, some Unit 3 scaffolding was identified by NRC field inspection to be in violation of procedural provisions for ensuring that seismic interactions would not impact the operability of nearby safety-related equipment. This failure to follow procedures is being treated as a Non-Cited Violation (NCV 50-423/99-14-08). (Section U3.M2.1)

- At Unit 3, an unresolved item is being opened to allow further NRC evaluation of whether a violation of 10 CFR 50.65(a)(1) and (a)(2) occurred with respect to: (1) the licensee's methods for establishing performance measures for high risk significant structures, systems and components; (2) failure of the licensee to place the station blackout (SBO) diesel in an (a)(1) status and to establish appropriate goals in the general time frame of April 13, 1999, following the second functional failure; (3) the licensee's method of establishing performance measures for the emergency diesel generators and SBO diesel (Unresolved Item 50-423/99-14-09). IFI 50-423/98-02-03 is closed. (Section U3.M8.3)

Engineering

- At Unit 2, the licensee identified in 1998 that certain safety-related cable trays and cables did not meet design basis requirements for separation and/or placement. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control, is being treated as a Non-Cited Violation (NCV 50-336/99-14-05). LER 50-336/98-18-00 & 01 are closed. (Section U2.E8.2)

- At Unit 2, the licensee identified in 1998 that certain containment pressure instruments did not meet design basis requirements for post loss of coolant accident pressure retention. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control, is being treated as a Non-Cited Violation (NCV 50-336/99-14-06). LER 50-336/98-24-00 is closed. (Section U2.E8.4)

- At Unit 2, the licensee identified in 1998 that pressurizer spray line operating procedures and practices did not meet the design basis requirements for reheating, maximum spray flow and other parameters affecting thermal fatigue parameters for the pressurizer spray line. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control is being treated as a Non-Cited Violation (NCV 50-336/99-14-07). LER 50-336/98-26-00 is closed. (Section U2.E8.5)

- The licensee system engineer appropriately conducted follow-up of observed corrosion on some safety-related Unit 3 valves. Material engineers evaluated the as-found conditions in the plant, determined that the immediate, adverse safety impact was minimal, and recommended a solution to eliminate further corrosion as a longer term corrective action. Overall licensee response to this issue was good. (Section U3.E1.1)

Plant Support

- Security and safeguards activities were conducted in a manner that protected public health and safety in the areas of access authorization, alarm stations, and protected area access control of personnel and packages. This portion of the program, as implemented, met the licensee's commitments and NRC requirements. A weakness was identified in the effectiveness of the security communications system. This weakness has been entered in the licensee's corrective action program. (Section S1)

- Protected area assessment aids, protected area detection aids, and personnel search equipment were determined to be well maintained and able to meet the licensee's commitments and NRC requirements. (Section S2)

- Security and safeguards procedures and documentation were properly implemented. Event logs were properly maintained and used to analyze, track, and address safeguards events. The logs indicated that there have been several breakdowns, involving the control of Safeguards information. This issue has been entered into the licensee's corrective action program. (Section S3)

- The security force members adequately demonstrated that they had the requisite knowledge necessary to effectively implement the duties and responsibilities of their positions. Security force personnel were being trained in accordance with the requirements of the Training and Qualification Plan. Weaknesses in the documentation of training were identified. These weaknesses have been entered into the licensee's corrective action program. (Sections S4, S5)

- Management support was adequate to ensure effective implementation of the security program, as evidenced by adequate staffing levels and the allocation of resources to support programmatic needs. (Section S6)

- Security Program audits were comprehensive in scope and depth, the audit findings were reported to the appropriate level of management, and the program was being properly administered. In addition, a review of the documentation applicable to the self-assessment program indicated that the program was being effectively implemented to identify and resolve potential weaknesses. (Section S7)

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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 reduced power to about 92 percent for cleaning of the “B” circulating water bay from November 29 through December 11, 1999. After that work was complete, the plant remained at a reduced power level, 95 percent power, to provide additional margin to reactor trip setpoints while the Channel “D” reactor protection system trips for thermal margin/low pressure, high power, and local power density were inoperable and in the tripped condition due to the failure of a Channel “D” hot leg resistance temperature detector on December 1, 1999. On December 18, 1999, the plant returned to full power after Channel “D” of the reactor protection system was restored to an operable status. 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. In general, the inspectors continued to note thorough turnovers and good communication practices among operators in the control room. However, the inspectors noted that the control operators had allowed plant power levels to exceed operational limits on several occasions. This issue is described in Section O8.1 of this report.

U2 O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) LER 50-336/99-011-00; Exceeding the Thermal Reactor Power Limit

The inspector performed an on-site review of Licensee Event Report (LER) 50-336/99-011-00 which involved five instances where the eight-hour average reactor thermal power based on secondary calorimetric data exceeded the licensed limit of 2700 megawatts. In all instances, the highest average power level was less than 0.2 megawatts thermal above the licensed limit. The licensee documented the events in Condition Reports M2-99-2312 and M2-99-2421. The LER states that the cause of the events was a lack of conservatism in the procedures and alarm setpoints used to limit reactor power. As corrective actions, operating procedures were changed to specify controlling reactor power below 2699.8 megawatts and alarm setpoints were changed to allow a timely response by operators prior to exceeding the limit. The licensee’s corrective actions were found acceptable. Because the licensed thermal power limit was exceeded by a small amount, the safety significance is considered minimal.

Therefore, this failure constitutes a violation of minor significance and is not subject to formal enforcement action. LER 50-336/99-011-00 is **closed**.

U2.II Maintenance

U2 M1 Conduct of Maintenance

M1.1 General Maintenance Observations

a. Inspection Scope (62707/61726)

During routine plant inspection tours, the inspectors observed, on a random sampling basis, maintenance and surveillance activities to evaluate the propriety of the activities and the functionality of systems and components with respect to technical specifications and other requirements.

b. Observations and Findings

The inspectors reviewed maintenance work orders and surveillance procedures and interviewed licensee field personnel to verify the adequacy of work controls and surveillance testing. The inspector observed a portion of activities performed under the following automated work orders (AWOs) and surveillance procedures:

- AWO M2-99-03609 — Valve 2-CS-16.1B Electrical Breaker Preventive Maintenance
- AWO M2-99-04703 — Valve 2-CS-16.1B Motor Operated Valve Preventive Maintenance
- AWO M2-99-03524 — “C” RBCCW Heat Exchanger Preventive Maintenance
- Procedure SP 2401D — RPS Trip Matrix Logic and Trip Path Relay Test
- Procedure SP 2601-D2 — Power Range Safety Channel and Delta T Calibration

The inspector found that maintenance work was being performed in accordance with approved work orders present at the work site. Overall, the conduct of the maintenance and surveillance activities was found acceptable. However, one concern was noted involving obtaining of necessary approvals for higher risk work activities.

On December 29, 1999, the licensee isolated valve 2-CS-16.1B, a containment sump recirculation isolation valve, to perform preventive maintenance activities. At the time, the “C” RBCCW heat exchanger was also removed from service for cleaning. As specified in procedure MP-20-WM-FAP02.1, “Conduct of On-Line Maintenance,” prior to removing the equipment from service, the licensee performed a risk assessment to evaluate the maintenance activities being performed simultaneously. The licensee determined that the maintenance activities placed them in an “Orange” risk condition. Procedure MP-20-WM-FAP02.1 states that an “Orange” designation signifies a condition where the combination of equipment unavailable represents a higher risk.

The inspector found that the licensee had appropriately evaluated the maintenance activities for risk and that plant management, as well as control room personnel, were aware that this maintenance placed them in an “Orange” condition. The inspector observed briefings of maintenance and operations personnel that reinforced the desire to expedite the performance of maintenance on valve 2-CS-16.1B to minimize the time the plant was in the “Orange” condition. The inspector found the licensee’s performance was good in recognizing the “Orange” condition and expediting maintenance activities.

The inspector identified a concern regarding procedure MP-20-WM-FAP02.1, Attachment 1, “Definitions,” which stated that Operations Manager approval is required for all planned “Orange” condition evolutions. Discussions with licensee management indicated they were unaware of the statement and therefore, the plant staff had not been documenting Operations Manager approval. The inspector determined that this was not a violation because the Operations Manager was aware of “Orange” condition activities, so, therefore, he had been approving such conditions. The licensee documented the inspector’s concern in Condition Report M2-00-0017, and changed procedure MP-20-WM-FAP02.1 to remove the statement regarding Operations Manager approval. The basis for removing the statement was they considered the Probabilistic Risk Assessment group to be the approval authority for what risk conditions are acceptable. The inspector found the licensee’s corrective actions acceptable.

c. Conclusions

Overall, the conduct of the maintenance and surveillance activities was found acceptable. However, the NRC identified that although the on-line maintenance procedure specified that Operations Manager approval was needed when the planned removal of equipment from service placed them in an “Orange” risk condition, the plant staff had not been documenting his approval. Because the Operations Manager was aware of the “Orange” conditions, he had approved the conditions. Therefore, no violation occurred. The licensee’s corrective action, which involved changing the on-line maintenance procedure to remove the statement regarding Operations Manager approval, was found acceptable.

M1.2 Maintenance Rule Functional Failures

a. Inspection Scope

The inspectors reviewed the licensee’s method of identifying Maintenance Rule Functional Failures (MRFFs) as part of the implementation of the Maintenance Rule (10 CFR 50.65) with respect to the equipment issues described in the following condition reports (CRs).

CR	M2-99-1664	(Dated 5/18/99) The setpoint for “A” Channel Thermal Margin/Low Pressure (TM/LP) is intermittently failing.
CR	M2-99-1765	(Dated 5/28/99) Channel “D” TM/LP setpoint was identified to be lower than expected. While performing a calibration, found coefficient out of specification due to dirty flow dependent setpoint selector switch (FDSSS).

CR	M2-99-2764	(Dated 10/25/99) The FDSSS was found to have dirty connections. Cycling the FDSSS causes all indications to return their normal values.
CR	M2-99-2994	(Dated 11/19/99) While monitoring key parameters, the "A" TM/LP setpoint was noted to be significantly lower than the other three channels.
CR	M2-99-3006	(Dated 11/19/99) TM/LP setpoint failed low due to connections through the FDSSS. This is a reoccurring problem. It was discovered that the TM/LP CPD-1-B/50 potentiometer was not making clean connection through the FDSSS.

b. Observations and Findings

The inspectors found that the above noted CRs described five failures of a the TM/LP potentiometer which resulted in a non-conservative movement of the TM/LP setpoint for the reactor protection system (RPS) for Unit 2. The failures were due to the contacts not making a clean connection through the FDSSS. As can be seen by the above noted CRs, the RPS had a recurring problem with the FDSSS oxidizing and giving erroneous setpoint indication. The maintenance activity to correct this condition was to cycle the FDSSS (i.e., clean the switch by cycling) which caused all indications to return their normal values. This failed condition was originally discovered on May 18, 1999, (CR M2-99-1664) and recurred on May 28, 1999 (CR M2-99-1765). The inspectors reviewed the details of these functional failures and the licensee's corrective actions and determined that no operability issues existed regarding these failures since individual channel operability was restored within the technical specification required action times. However, the inspectors questioned why the occurrence on May 28, 1999, (CR M2-99-1765) had not been considered as the repetitive maintenance rule functional failure that caused the performance measures for the RPS system to be exceeded.

The licensee issued CR M2-99-3226 to review this condition for the purpose of evaluating the need for additional corrective action. Engineering Department Instruction (EDI) 30710, Rev. 1, "Maintenance Rule Functional Failures ," requires that both instrument drift two times the acceptable level and failure of one channel of the instrument, no matter how many redundant channels there are, be identified as an MRFF. Also, EDI 30730, "Maintenance Rule Goal Setting and Monitoring," requires considerations of goal setting and movement into an (a)(1) category for repetitive functional failures. At the time of this inspection, this determination had not been accomplished by the licensee.

Paragraph (a)(1) of 10 CFR 50.65, Maintenance Rule, requires that when the performance or condition of a structure, system, or component does not meet established goals, appropriate corrective action shall be taken. As stated above, the licensee failed to recognize, until after being identified by the inspectors, that the established performance measures of no repetitive functional failures for the Unit 2 RPS was exceeded on May 28, 1999, and again exceeded in October and November 1999, when another three functional failures occurred. The licensee failed to place the system into an (a)(1) status and establish goals commensurate with safety in violation of 10 CFR 50.65(a)(1). This violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR M2-99-3226.

c. Conclusion

The licensee failed to recognize that the established performance measures of no repetitive functional failures for the Unit 2 RPS was exceeded on May 28, 1999, and again exceeded in October and November 1999, when another three functional failures occurred. The licensee failed to place the system into an (a)(1) status and establish goals commensurate with safety in violation of 10 CFR 50.65(a)(1). This violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. **(NCV 50-336/99-14-01)**

M1.3 Troubleshooting of Reactor Protection System Problems

a. Inspection Scope (62707/37551)

The inspector evaluated various problems that have affected the reactor protection system (RPS) during the inspection period and reviewed the actions taken to address these problems. The inspector also observed portions of work activities and reviewed the documentation associated with Automated Work Orders (AWOs) M2-99-13193 and M2-99-12774, which involved troubleshooting of local power density pre-trip alarms on RPS Channel "D" and troubleshooting and repair of the Channel "A" linear range nuclear instrument drawer, respectively. The inspector discussed the troubleshooting activities and overall system performance with instrumentation and control technicians and the responsible system engineer.

b. Observations and Findings

The Unit 2 RPS has been subject to both isolated and chronic problems that have affected system operation. The inspector reviewed the following isolated problems and the corrective actions implemented to address them:

1. The reactor coolant system loop 1 hot leg resistance temperature detector input to RPS Channel "D" began spiking on December 1, 1999. The spiking induced Channel "D" reactor trip signals for local power density, high power, and thermal margin/low pressure. The operators declared the affected trip signals inoperable and executed the actions required by technical specifications. The affected trip signals were restored to an operable status by implementing Temporary Modification 2-99-031 to substitute the reactor coolant system loop 2 hot leg resistance temperature detector input to RPS Channel "D" for the defective input. With both hot leg temperature inputs to RPS Channel "D" from loop 2, this channel would respond more slowly to certain asymmetric events requiring RPS actuation (e.g., a large main steam line break upstream of the non-return valve). However, the licensee demonstrated that through diverse trip signals within the channel and a reduction in the unrodded radial flux peaking factor limit, the safety margin would not be reduced for these events. The inspector found that the temporary modification had an adequate technical basis and was acceptable.

2. Operators observed linear range nuclear instrument power swings on Channel "A" while plant power was stable. This problem was effectively repaired under AWO M2-99-12774 by replacement of two circuit modules in the linear range power drawer on November 4, 1999. Due to difficulties in obtaining replacement parts, Channel "A" was unavailable for 46 hours.

The inspector also reviewed the following chronic problems and the licensee's plans to address these problems:

1. Infrequent, but recurring non-conservative changes in the thermal margin/low pressure trip setpoint, particularly the Channel "A" setpoint, have occurred due to increased resistance in the flow dependent setpoint selector switch for individual channels. As a preventive measure, the licensee has been cycling the flow selector switch monthly to prevent the increased resistance at the switch contacts that causes a non-conservative change in the thermal margin/low pressure trip setpoint. However, as described in Section U2 M1.2 of this report, this maintenance activity has been ineffective. Because the switch has no needed function, the licensee plans to remove this switch from the circuit to correct the problem. The licensee is evaluating this modification for implementation prior to the next refueling outage.

2. Frequent local power density pre-trip alarms have occurred, particularly on Channel "D." After extensive troubleshooting under AWO M2-99-13193, the licensee determined that the frequent local power density pre-trips result from actual plant conditions and a small operating window within the pre-trip setpoint boundary rather than from a problem with the RPS sensors or instrumentation. The licensee plans to broaden the operating range by changing the pre-trip setpoints. This modification is currently scheduled for January 2000.

3. Input signal noise has caused RPS response, including one instance where noise was manifested as a turbine trip signal on Channel "B." To address signal noise problems, the licensee plans to replace wiring subject to signal noise generation with shielded wiring during the next refueling outage, which is scheduled to begin in April 2000.

4. System obsolescence has resulted in spare parts procurement difficulties. Difficulty in obtaining satisfactory replacement parts has contributed to longer than necessary unavailability of the affected RPS channel. The licensee plans to address system obsolescence by replacing the RPS. The licensee has scheduled replacement of the nuclear instrumentation portion prior to the next refueling outage.

The inspector evaluated the effect of the above issues with respect to RPS operability. The inspector considered the isolated failures of the Channel "A" linear range nuclear instrument drawer and the Channel "D" loop 1 hot leg resistance temperature instrument as events representative of expected random component failures. The licensee complied with technical specification requirements when the affected channels were inoperable and implemented appropriate corrective maintenance to restore the channels to operable status. The frequent local power density pre-trip alarms represent an operator distraction rather than a functional problem with the RPS. The licensee has assigned an appropriate priority to the elimination of this distraction, as indicated by scheduled modification in January 2000, and the plant operators have maintained plant power level at about 99.3 percent to reduce the frequency of the distracting alarms. Similarly, the signal noise generation and system obsolescence represent a slight increased potential for an inadvertent reactor trip rather than a threat to the reliability of the system in performing its safety function.

The inspector found the infrequent, non-conservative changes in the thermal margin/low pressure trip setpoint somewhat more significant in that a recurring condition was rendering a trip channel inoperable. The thermal margin/low pressure setpoint is the higher of a calculated value, which is provided by the core protection calculator based on reactor power and core power distribution, and a floor value, which is approximately equal to the technical specification minimum value for the nominal core power distribution at full power. On five instances during the period from May to November 1999, including four instances affecting RPS Channel “A,” the thermal margin/low pressure setpoint for one channel decreased to the floor value, which was slightly below the technical specification minimum setpoint for the core power distribution existing at the time. The licensee complied with technical specification requirements during each instance by declaring the trip channel inoperable, placing the affected channel in the bypassed condition until the channel was restored to an operable status, and restoring the channel to operable status within the 48 hour allowed outage time. Although the inspector found that maintenance activities to clean the flow dependent setpoint selector switch returned the affected channel to operable status, the recurrent nature of the problem, despite preventive maintenance activities, indicated that the RPS was in a degraded state.

As late as November 1999, the licensee planned to continue with preventive maintenance activities and repair the switch after the next refueling outage. The inspector was concerned that these actions were not timely based on the potential for multiple channels to be affected by the non-conservative change in the thermal margin/low pressure setpoint. The inspector discussed this concern with the licensee’s engineering management. As an interim corrective action, the licensee established a computer alarm to promptly alert operators when the thermal margin/low pressure setpoint drifts downward from its normal value at full power. This alarm supplements the permanent control board alarm that annunciates when the setpoint reaches the floor value. In addition, the licensee realigned engineering resources to support a schedule to remove the flow dependent setpoint selector switches from each channel of the RPS prior to the next refueling outage, which begins in April 2000. Although the licensee’s actions were untimely, the inspector found that this interim corrective action is adequate to address operability concerns until the planned modification is implemented because the computer alarm provides prompt notification to the operators of setpoint drifts.

c. <u>Conclusions</u>

The NRC concluded that the licensee’s determination of continued operability of the Unit 2 RPS, despite some degradation, was adequately founded. The majority of issues pose only a minimal increase in the probability of an inadvertent reactor trip or a distraction to the control operators and have no effect on the system’s safety function.

The licensee has implemented or scheduled appropriate measures to address the degraded conditions consistent with their importance to safety. However, the licensee was untimely in developing a plan to address recurrent instances where an RPS channel was rendered inoperable due to a drifting thermal margin/low pressure setpoint. This untimeliness relates to a violation described in Section U2 M1.2, where the NRC found that the licensee failed to identify that system performance goals with respect to maintenance preventable functional failures, which were established by the licensee pursuant to 10 CFR 50.65, had not been met.

U2 M8 Miscellaneous Maintenance Issues

M8.1 <u>(Closed) IFI 50-336/98-02-01; Implementation of Two Maintenance Rule Issues: (1) System Engineer Determination of Maintenance Rule Functional Failures and (2) Licensee's Action to Clarify Definitions of Functional Boundaries Between Interfacing and Overlapping Systems</u>

a. <u>Inspection Scope (92902)</u>

The inspectors reviewed the licensee's response and related actions to address Inspector Follow-up Item (IFI) 50-336/98-02-01. This IFI was opened to review two (2) specific items after the unit had been operating for a period of time to allow gathering real plant data related to system performance. One of the items dealt with licensee's action to clarify definitions of functional boundaries between interfacing and overlapping systems. The second item dealt with System Engineer determination of maintenance rule functional failures (MRFFs) following plant restart. Examples included failures associated with the control room air conditioning (CRAC) exhaust fans and safety injection tanks (SIT) system.

The inspectors conducted in-office and onsite reviews of the IFI. This review included a review of Unit 2 engineering and maintenance rule procedures, associated engineering evaluations/memorandums, work activities, and corrective action documents in the licensee's corrective action process. In addition, these items were discussed with operations personal and system engineers.

b. Observations and Findings

The item concerning physical boundaries for functions that relied on components in multiple systems that were not clearly defined for performance monitoring is closed based on the scheduled completion of corrective actions outlined in CR 98019252. All actions are scheduled to be completed by March 2000 including all related training for system engineers and operators and an issue identified by the inspectors related to cascading unavailability times. When a structure, system, or component (SSC) becomes unavailable, the associated support systems would also be considered unavailable based on the functions provided and the methods used by the probabilistic risk assessment (PRA) staff to establish performance criteria. Based on discussions with the licensee's PRA staff, the tracking of unavailability for both the primary and support SSCs is essential since the PRA staff established maintenance rule performance criteria (unavailability times) using the cascading concept.

The item on System Engineers correctly determining MRFFs for two specific SSCs is closed. The inspectors reviewed and determined that the functional failures associated with the control room air conditioning (CRAC) exhaust fans and safety injection tanks (SIT) system were appropriately handled by the licensee based on a review of the following: Condition Reports (CRs) M2-96-0196 and M2-98-1190, Automated Work Orders (AWOs) M2-98-03317 and M2-98-03462, level transmitter LT 311 on the SIT (CR M2-98-1105), maintenance rule expert panel meeting minutes dated August 7, 1998; and Adverse Condition Reports (ACRs) 04066, 03529, 04775, 04794, 04260, and 06732.

c. Conclusion

The licensee made acceptable maintenance rule functional failure determinations and instituted appropriate corrective actions to address the failures on the CRAC exhaust fans and SIT system. The item on physical boundaries on SSC functions will be closed based on the licensee tracking completion of all corrective actions associated with CR 98019252 which is scheduled for completion in March 2000. IFI 50-336/98-02-01 is **closed**.

M8.2 (Closed) IFI 50-336/98-02-02; Implementation of Four Maintenance Rule Issues: (1) Review Effectiveness of Licensee's Maintenance and Performance Monitoring; (2) Balancing Reliability and Unavailability and (3)&(4) Review Operators Knowledge and Use of On-Line Maintenance Risk Assessment

a. Inspection Scope (92902)

The inspectors reviewed the licensee's response and related actions to address Inspector Follow-up Item (IFI) 50-336/98-02-02. This IFI was opened to review four (4) specific items after the unit had been operating for a period of time to allow gathering real plant data related to performance. The first item dealt with the licensee's ability to assess the effectiveness of maintenance and performance monitoring. The second item dealt with balancing reliability and unavailability. The third and fourth items dealt with reviewing operators knowledge of on-line maintenance risk assessment and the operators use of on-line maintenance risk assessment.

The inspectors conducted in-office and onsite reviews of the IFI. This review included a review of Unit 2 engineering, operations, work control and maintenance rule procedures, associated engineering evaluations/memorandums, work activities, and corrective actions documents in the licensee's corrective action process. In addition, the items were discussed with operations personal and system engineers.

b. Observations and Findings

The item on the effectiveness of the licensee's maintenance and performance monitoring programs is closed based on a sample review of system performance and monitoring on various systems and based on a review of the licensee's Periodic Assessment of the Maintenance Rule for Units 2 & 3, dated December 17, 1999. The performance criteria established for many high risk significant systems in Unit 3 was found to be in question and will be tracked by the completion of licensee's corrective action for Condition Report M3-99-3966 and Unresolved Item 50-423/99-14-01.

The item on balancing reliability and unavailability is closed based on a review of the completed periodic assessments in May 1998 and the "Periodic Assessment of the Maintenance Rule Program" report for Units 2 & 3, dated December 17, 1999, which appropriately addressed balancing reliability and unavailability as defined in 10 CFR 50.65 (a)(3). Balancing reliability and unavailability program requirements were described in Attachment 1 to Engineering Department Instructions (EDI) No. 30740, "Maintenance Rule Periodic Assessment". Several items remained open from the Units 2 & 3 past periodic assessments completed in May 1998, and are being tracked under CRs identified in Attachment 8-1 of the recently completed periodic assessment dated December 17, 1999.

The item on reviewing operators knowledge of on-line maintenance risk assessment is closed based on the licensee's appropriate development and implementation of their on-line and shutdown safety assessment program as outlined in the licensee's procedures "Conduct of On-Line Maintenance," MP-20-WM-FAP02.1 and "On-Line Maintenance, MP-20-WM-SAP02". Based on a review of lesson plan material and interviews with licensed reactor and senior reactor operators, the inspectors determined that the operators had received training and were knowledgeable on various aspects of the maintenance rule including on-line maintenance risk assessment.

The item on reviewing operators use of on-line maintenance risk assessment following plant return to on-line is closed. The inspectors reviewed a sample of on-line corrective maintenance emergent work activities performed over the last several months and concluded that risk had been appropriately considered in the performance of this work.

c. Conclusion

The licensee made acceptable determinations and instituted appropriate corrective actions to address the four (4) items: review the effectiveness of the licensee's maintenance and performance monitoring; balancing reliability and unavailability; operators knowledge and use of on-line maintenance risk assessment. IFI 50-336/98-02-02 is **closed**.

M8.3 (Closed) LER 50-336/98-20-00; Safety Injection Recirculation Header Inservice Visual Inspection Requirements

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-20-00, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of testing documentation.

b. Findings and Observations

On September 29, 1998, while Unit 2 was defueled, the licensee identified that certain portions of the safety injection (SI) recirculation header piping had historically not been visually tested, in accordance with American Society of Mechanical Engineers (ASME) Code, Section XI, Article IWV-5000, "Visual Testing" (VT). The code testing was required by Unit 2, TS 4.0.5.

The licensee's corrective actions included procedure updates, drawing changes, verification of SI recirculation header flow testing data and the adequate performance of selected visual tests. Failing to establish and implement adequate testing to ensure that the requirements of ASME Section IX were met, is a violation of Unit 2, TS 4.0.5. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the issue being entered into the licensee's corrective action program. This issue was entered as Condition Report M2-98-2601. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate.

c. Conclusions

The licensee identified in 1998 that Unit 2 TS required, ASME code visual tests, had not been performed on portions of SI recirculation header piping. This is a violation of Unit 2 TS 4.0.5. The licensee's corrective actions were found acceptable. This violation of TS 4.0.5, is being treated as a **Non-Cited Violation (NCV 50-336/99-14-02)**. LER 50-336/98-20-00 is **closed**.

M8.4 (Closed) LER 50-336/98-23-00; Containment Air Recirculation Fan Testing

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-23-00, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of testing documentation.

b. Findings and Observations

On September 24, 1998, while Unit 2 was defueled, the licensee identified that the low speed portions of containment air recirculation (CAR) fan testing did not meet the requirements of Unit 2 technical specification (TS) surveillance requirement (SR) 4.6.2.1.2 (a). The TS SR requires that the CAR fans be started in slow speed once every 31 days when the unit is in Modes 1 through 3. Although historically, the CAR fans were tested once every 31 days, the tests did not include starting each of the four CAR fans from a stopped, de-energized condition.

The licensee's corrective actions included procedure changes, verification of historical CAR fan starting circuitry test data and the adequate testing of each of the CAR fans. Failing to establish and implement adequate CAR fan testing is a violation of Unit 2, TS 4.6.2.1.2. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the issue being entered into the licensee's corrective action program. This issue was entered as Condition Report M2-98-2894. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate.

c. Conclusions

The licensee identified in 1998 that Unit 2 TS required, CAR fan start testing, had historically not been performed. This is a violation of Unit 2 TS 4.6.2.1.2. The licensee's corrective actions were found acceptable. This violation of TS 4.6.2.1.2, is being treated as a **Non-Cited Violation (NCV 50-336/99-14-03)**. LER 50-336/98-23-00 is **closed**.

M8.5 (Closed) LER 50-336/98-25-00; Check Valve Testing Requirements

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-25-00, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of testing documentation.

b. Findings and Observations

On November 11, 1998, while Unit 2 was defueled, the licensee identified that certain check valves had historically not been tested at design maximum flow conditions, in accordance with American Society of Mechanical Engineers (ASME) Code, Section XI, “Inservice Testing”. The ASME Code testing is required by Unit 2 TS 4.0.5.

The licensee’s corrective actions included procedure updates, verification of historical performance, flow and position indication testing data, and the adequate performance of selected full flow tests. No adverse conditions were identified. Failing to establish and implement adequate testing to ensure that the requirements of ASME Section IX were met is a violation of TS 4.0.5. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the issue being entered into the licensee’s corrective action program. This issue was entered as Condition Report M2-98-3396. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate.

c. Conclusions

The licensee identified in 1998 that TS required check valve full flow tests had not been performed in accordance with ASME Section XI requirements, on specific check valves. This is a violation of TS 4.0.5. The licensee’s corrective actions were found acceptable. This violation of TS 4.0.5, is being treated as a **Non-Cited Violation (NCV 50-336/99-14-04)**. LER 50-336/98-25-00 is **closed**.

U2.III Engineering

U2 E1 Conduct of Engineering

E1.1 Year 2000 Project Readiness Review

a. Inspection Scope (71750)

The inspector reviewed the licensee’s contingency plan for the Year 2000 (Y2K) rollover and observed implementation of the plan from December 31, 1999, into January 1, 2000.

b. Observations and Findings

The licensee’s contingency plans provided the staffing, organization, and mitigation strategies to address unexpected, but possible Y2K related issues. The staffing plan provided for additional personnel in all areas essential for operations, with an emphasis on instrumentation and information technology specialists.

On December 31, 1999, the inspector observed that the licensee had staffed its Y2K contingency organization. Throughout the rollover period, the licensee monitored a variety of information sources for indications of potential significant Y2K related issues.

The additional personnel were used to monitor computers and other components with embedded digital devices during critical transition periods. No significant problems were identified.

c. Conclusions

The licensee developed and implemented contingency plans to address potential Y2K related issues at Millstone Units 2 and 3. No significant problems developed during the Y2K rollover period.

U2 E8 Miscellaneous Engineering Issues

E8.1 (Closed) LER 50-336/98-16-00; Safety Injection System Administrative Controls

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-16-00, which addresses certain postulated post loss of coolant accident (LOCA) conditions in which the operability and design basis of the safety injection tanks (SIT) could be affected. The postulated conditions are related to the administrative controls applied to a normally locked closed safety injection (SI) system manual isolation valve connected to the SIT recirculation branch line. The inspector reviewed the LER, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of plant modification documentation.

The postulated conditions resulted from the licensee's corrective actions for a number of NRC violations involving the Unit 2 design basis. Failing to adequately establish and implement design controls to ensure that the SI system design criteria were correctly translated into specifications, drawings and procedures, is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. Because, the condition was postulated, reported and corrected by the licensee as part of its response to previous NRC violations, the condition is considered to be dispositioned from an enforcement perspective. This issue was entered into the licensee's corrective action program as Condition Reports M2-98-1704. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate. LER 50-336/98-16-00 is **closed**.

E8.2 (Closed) LER 50-336/98-18-00 & 01; Spacial Separation of Redundant Cables

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-18-00 & 01, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of plant modification documentation.

b. Findings and Observations

On December 18, 1998, while Unit 2 was defueled, the licensee identified that certain safety-related cable trays did not meet Institute of Electrical and Electronic Engineers (IEEE) standards 279-1971 and 308-1971. The IEEE standards were incorporated into the Unit 2 design basis by Unit 2 FSAR, Section 8.7.

The licensee's corrective actions included procedure updates, drawing changes, mechanical modifications, verification of safety-related cable tray and cable placements through system walkdowns, and ongoing long term generic reviews. Failing to adequately establish and implement design controls to ensure that safety related cable tray spacing and placement design bases were correctly translated into specifications, drawings and procedures, 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 consistent with Section VII.B.1.a of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the issue being entered into the licensee's corrective action program. This issue was entered as Condition Report M2-98-2401. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate.

c. Conclusions

The licensee identified in 1998 that certain Unit 2 safety-related cable trays and cables did not meet design basis requirements for separation and/or placement. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control, is being treated as a **Non-Cited Violation (NCV 50-336/99-14-05)**. LER 50-336/98-18-00 & 01 are **closed**.

E8.3 (Closed) LER 50-336/98-19-00; Auxiliary Feedwater Regulating Valve Response to a High Energy Line Break

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-19-00, which addresses certain auxiliary feedwater (AFW) system non-safety related components that had been credited with mitigating the consequences of a design basis high energy line break (HELB). The inspector reviewed the LER, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of plant modification documentation.

As part of its corrective actions for NRC Non-Cited Violation 50-336/98-202-02 and a number of related NRC violations involving the Unit 2 design basis, the licensee implemented extensive reviews of the Unit 2 design basis. The licensee's corrective actions for the specific conditions identified in LER 50-336/98-26-00 included procedure updates, drawing changes, mechanical modifications, verification of historical performance and test data, and revised post-HELB engineering calculations. Failing to adequately establish and implement design controls to ensure that the AFW system design criteria were correctly translated into specifications, drawings and procedures, is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. Because, the condition was identified, reported and corrected by the licensee as part of its response to a previous NRC violation, the condition is considered to be dispositioned from an enforcement perspective. This issue was entered into the licensee's corrective action program as Condition Reports M2-98-2503, 2826 and 2780. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate. LER 50-336/98-19-00 is **closed**.

E8.4 (Closed) LER 50-336/98-24-00; Potential Containment Leakage Path

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-24-00, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of plant modification documentation.

b. Findings and Observations

On October 30, 1998, while Unit 2 was defueled, the licensee identified that certain model 11 Foxboro containment pressure instruments did not meet FSAR, Section 5.2.8.2.1, design basis requirements for post loss of coolant accident (LOCA) pressure retention.

The licensee's corrective actions included drawing changes, instrument replacements, and verification of the installed containment pressure instrumentation configuration. Failing to adequately establish and implement design controls to ensure that the safety-related design bases for containment pressure instruments were correctly translated into specifications, drawings and procedures, 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 consistent with Section VII.B.1.a of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the issue being entered into the licensee's corrective action program. This issue was entered as Condition Report M2-98-3267. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate.

c. Conclusions

The licensee identified in 1998 that certain Unit 2 containment pressure instruments did not meet FSAR design basis requirements for post-LOCA pressure retention. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control, is being treated as a **Non-Cited Violation (NCV 50-336/99-14-06)**. LER 50-336/98-24-00 is **closed**.

E8.5 (Closed) LER 50-336/98-26-00; Pressurizer Spray Line Fatigue Limits

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-26-00, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of plant modification documentation.

b. Findings and Observations

On December 23, 1998, while Unit 2 was defueled, the licensee identified that historically, pressurizer spray line operating procedures and practices did not meet the design basis established in the FSAR for reheating, maximum spray flow and other parameters affecting thermal fatigue parameters for the pressurizer spray line. The Unit 2 FSAR incorporated American Society of Mechanical Engineers (ASME) Code, Section III, fatigue and thermal cycling criterion into the Unit 2 design basis. The licensee's corrective actions included procedure updates; drawing changes; mechanical modifications; engineering analysis of historical performance, temperature and flow data; and ongoing long term generic reviews of other safety related systems. No adverse physical conditions were identified. Failing to adequately establish and implement design controls to ensure that the pressurizer spray line design criteria were correctly translated into specifications, drawings and procedures, 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 consistent with Section VII.B.1.a of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the issue being entered into the licensee's corrective action program. This issue was entered as Condition Report M2-98-3839. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate.

c. Conclusions

The licensee identified in 1998 that pressurizer spray line operating procedures and practices did not meet the design basis established in the FSAR for reheating, maximum spray flow and other parameters affecting thermal fatigue parameters for the pressurizer spray line. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control is being treated as a **Non-Cited Violation (NCV 50-336/99-14-07)**. LER 50-336/98-26-00 is **closed**.

E8.6 (Closed) URI 50-336/98-206-02; Safety Parameter Display System

a. Inspection Scope (92903)

The inspector performed an on-site inspection of the licensee's actions to address Unresolved Item (URI) 50-336/98-206-02. The evaluation included a review of the licensee's documents to close the issue, additional applicable documentation, as needed, and interviews of responsible engineering and supervisory personnel.

b. Observations and Findings

URI 50-336/98-206-02 involved two examples where the safety parameter display system (SPDS) did not meet the licensing basis commitments the licensee made in a letter dated October 8, 1986. This letter described how the SPDS satisfied Supplement 1 to NUREG 0737, “Clarification of TMI Action Plan Requirements.” The first example involved the following statement: “The SPDS is ‘on’ at all times during operating Modes 1, 2, and 3. During normal operations, all safety functions are green and are displayed at all times.” The URI concerned the fact that the Unit 2 operators had been trained to display SPDS only upon entry into emergency operating procedures. As described in a letter dated December 30, 1999, the licensee addressed this concern by implementing administrative controls to ensure that at least one of the four control room display monitors shows the SPDS overview. In addition, an SPDS modification is currently scheduled before the next refueling outage that installs a dedicated monitor for continuously displaying SPDS in the control room. The inspector found the licensee’s corrective actions to be acceptable.

The second example in which the SPDS did not meet licensing basis commitments involved the following statement: “The status of each of the six safety functions for the selected procedure is indicated by one of two colors. The green color indicates that the safety functions are not exceeded. A red color indicates that the limits are exceeded.” The URI concerned the fact that the SPDS display had been modified to no longer use the colors (or any other alerting mechanism) to continually indicate the status of the six safety functions. As described in a letter dated March 11, 1999, the licensee addressed this discrepancy by changing the licensing basis using the10 CFR 50.59 process to reflect that the current SPDS display provides the operators with the plant parameters, but relies on operators to evaluate the parameters.

After reviewing the licensee’s actions, the inspector was concerned that the current SPDS requires operators to scroll through multiple screens to assess the status of the six critical safety functions. Supplement 1 to NUREG 0737, Section 4.1.a, states that, “The SPDS should provide a concise display of critical plant variables to the control room operators to aid them in rapidly and reliably determining the safety status of the plant.” NUREG 1342, “A Status Report Regarding Industry Implementation of Safety Parameter Display Systems,” describes that operator decision making can be hampered when displays are widely dispersed because it does not facilitate the comparison of variables or the integration of various symptoms within the same time frame. This induces operators to fixate on a limited set of plant variables and give undue attention to irrelevant plant anomalies while safety functions could be in jeopardy. NUREG 1342 also describes that Supplement 1 to NUREG 0737 can be satisfied by either providing a dedicated, single display of plant variables, or by providing a hierarchy of display “pages” on a single monitor with perceptual cues to alert the user to changes in the safety function status of the plant. NUREG 1342 states that SPDS designs were considered unacceptable when they provided neither a continuous display of variables nor an alerting mechanism, such as the safety function status indicators.

Based on the NRC position provided in NUREG 1342, the inspector discussed his concern that the Millstone Unit 2 SPDS provided neither a continuous display nor an alerting mechanism with licensee management. In a letter dated January 13, 2000, the licensee committed to modify SPDS to provide the green and red safety function status indicators by no later than the end of refueling outage 14. The inspector found the proposed modification to be acceptable in addressing the concern.

c. Conclusions

The licensee's corrective actions were found acceptable in addressing the concerns with SPDS that were discussed in URI 50-336/98-206-02. URI 50-336/98-206-02 is **closed**. No violation of NRC requirements was identified.

Report Details

Summary of Unit 3 Status

Unit 3 began the inspection period on November 23, 1999, operating at 100 percent power. On November 25, operators reduced power to approximately 75%, as requested by ISO New England due to a fire near power lines several miles offsite. During this period, two 345 Kv power lines were available to supply offsite power to Millstone Station. Full power operation was restored later that day. No plant problems were encountered related to the transition from December 31, 1999 to January 1, 2000. Unit 3 continued to operate at 100% through the end of the report period on January 3, 2000.

U3.I Operations

U3 O1 Conduct of Operations

O1.1 Operational Activities and Control Room Observations

a. Inspections Scope (71707)

The inspector conducted frequent tours of the control room, examining the status of plant equipment, reviewing logs, and observing operator shift turnovers and the conduct of specific operational evolutions. The inspector discussed with the licensed operators and shift managers the governing technical specifications (TS) for certain preventive maintenance and surveillance activities and noted entries into the applicable limiting conditions for operation (LCOs). As appropriate, plant inspection-tours were conducted to verify field equipment status consistent with the observed operational controls and to check the affected component tagging.

b. Observations and Findings

The inspector evaluated the licensee's handling of certain operability, reportability, and TS compliance issues, raised as a result of generic NRC communications, inspector observations, or internal licensee reviews required to meet regulatory requirements. Included among these assessment activities were reviews of the following documents and the resultant licensee conclusions:

- Reportability Determination for Condition Report (CR) M3-99-0802, titled "Entry into Technical Specification 3.0.3 due to Both Trains of the Quench Spray System (QSS) Being Rendered Momentarily Inoperable", concluded that one train of the QSS was actually operable, despite the unavailability of supporting ventilation equipment for some period of time. Consequently, the licensee determined that this condition did not involve an entry into TS 3.0.3 and that the condition was not reportable pursuant to 10 CFR 50.73.

- Technical Specification Change Request 3-12-99 was submitted by the licensee to the NRC on November 29, 1999, to address the need for using an updated standard in the testing of nuclear-grade activated charcoal that is used in safety systems governed by the Unit 3 TS requirements. Since the existing TS provisions specified compliance with the earlier standard, the licensee's regulatory affairs staff issued a memorandum (RA-99-248), dated December 9, 1999, noting the NRC recognition in Generic Letter 99-02 that enforcement discretion may be required to eliminate unnecessary testing. The documented Regulatory Affairs position indicates that not only is enforcement discretion on this matter implicitly provided, but also that compliance with the updated testing standards bounds the existing TS requirements. Thus, licensee commitments and performance in response to Generic Letter 99-02 also meet present Unit 3 license requirements.

- Operating Procedure OP 3304A Section 4.17 discusses the steps and operational provisions for establishing an alternate cooling water injection flow path to the reactor coolant pump (RCP) seals, should such actions be required (e.g., emergency operating procedure direction). When in such an alignment, a question of component operability arises because TS 4.4.6.2.1 surveillance requirements may not be met because of a specified flow modulating valve position. The licensee issued CR M3-99-3954 to document this apparent TS/OP conflict, to determine whether the applicable TS actions are required when the unit is placed in this alternate mode of seal injection, and to evaluate the operational criteria for the reactor coolant system leakage to the RCP seals. The recommended CR corrective actions were appropriately directed to the potential TS compliance concerns.

The inspector also assessed the operational controls that were instituted on December 28, 1999, to compensate for a failed area heater in the auxiliary building. The Unit 3 Technical Requirements Manual specifies that two trains of four heaters are required whenever the outside temperature is less than or equal to 17° F. The inspector confirmed that the ambient outside temperature did not drop to the temperature limit, which would have required declaring the corresponding train of the charging system inoperable and a corresponding entry into the charging system TS actions. Corrective measures were implemented to restore the inoperable heater, but subsequent inspections and actions by the licensee resulted in another heater being rendered degraded, but available for operation, over the course of a few days. The inspector reviewed the operations logs for the purpose of checking how this degraded heater condition was tracked.

While a priority alarm point log and a temporary log to inspect equipment conditions were available to the operators should the outside air temperature drop to 17° F, the inspector determined that the equipment checks would only verify electrical breaker position for the eight affected heaters, without noting or assessing the impact of degraded heater condition. The licensee issued a Condition Report Engineering Disposition (CRED) Form for CR M3-99-4183, documenting the nonconforming condition of the degraded heater assembly and the technical justification for operation of the heater. Upon further questioning by the inspector, the licensee confirmed that the operations logs, including any temporary logs created during the relevant time frame, did not document the degraded (albeit available) condition of the nonconforming area heater. The licensee then issued another condition report , CR M3-00-0137, to document an inconsistent use in the Shift Turnover Log to track nonconforming or degraded conditions affecting safety-related component operability. The inspector discussed this issue with the Manager of Operations, reviewed all the relevant CRs and associated documentation, and determined that this was a minor tracking/documentation concern, since the degraded heater, while not fully operable, had been evaluated by engineering personnel for availability and operation.

Additionally, while assessing the licensee's response to some equipment problems with the Station Blackout (SBO) diesel generator start test in accordance with surveillance procedure SP 3646D.1, the inspector reviewed the relevant CRs (M3-00-31 & 00-47), noting that the licensee determined that the various equipment concerns and diesel start failures were not reportable to the NRC. The inspector also reviewed the system operating procedure, OP 3346D, for the Station Blackout Diesel and the Unit 3 Station Blackout Safe Shutdown Scenario Document, SP-EE-363 (Revision 3). It was noted that Battery 5 provides control power for load stripping of the normal bus and closing the SBO diesel generator tie breaker to either of the two vital 4.16 Kv buses. A battery 5 ground had been identified by the licensee during the same week of the SBO diesel generator outage and testing activities. The inspector questioned whether the impact of such grounded conditions would be appropriately reflected in the SBO diesel generator availability considerations.

As a result of the review of the identified SBO diesel generator problems, the inspector further discussed with the licensee's Regulatory Affairs personnel what criteria would be used to further assess the operability, reportability, and licensing-basis issues involving the SBO diesel generator. It was noted that the problems associated with CRs M3-00-0031 and 0047 were documented as maintenance rule functional failures. While the loss of all alternating current power is not a design-basis event at Unit 3, the SBO scenario is subject to regulatory requirements (10 CFR 50.63). The licensee's evaluation of the ability to "cope" with such a SBO scenario is available for NRC review. As a result of the problems documented in the CRs noted above, the licensee staff plans to further evaluate the handling of SBO equipment concerns, relative to the specific Unit 3 coping analysis.

During the conduct of several plant inspection-tours to check equipment status and verify proper operational controls, the inspector also examined the access points, postings, and barricades associated with radiological control areas (RCAs) and other radiation boundaries. One specific RCA boundary and posting within the Unit 3 auxiliary building was discussed further with the Station Radiological Protection Manager and determined to be consistent with the requirements of the health physics (HP) operations procedure, RPM 2.4.1 (Revision 2) for the "Posting of Radiological Control Areas". The inspector also discussed with HP technicians a recent change in the access point controls to the engineered safety features building and the segregation, marking, and control of materials planned for release from the auxiliary building RCA access point. Radiation area, RCA, and as-low-as-is-reasonably-achievable (ALARA) postings were found to be in compliance with the station radiation protection program requirements.

c. <u>Conclusions</u>

The established Unit 3 operational and radiological controls were adequate to provide for the safe implementation of plant evolutions and control room activities, as well as for the effective handling and tracking of plant equipment status. Issues involving component operability, availability, reportability, and regulatory compliance were appropriately addressed by the licensee staff.

U3.II Maintenance

U3 M1 Conduct of Maintenance

M1.1 Maintenance & Surveillance Observations

a. Inspection Scope (61726, 62707)

The inspector observed portions of the following maintenance and surveillance activities, discussed the conduct of work and controls with responsible personnel, and reviewed selected test results.

- SP 3614F.9 Control Building Chilled Water Valve Operability Test
- SP 3623.2-1 Cycle Test of HP Turbine Stop Valve and LP Turbine Combined Intermediate Stop and Intercept Valves (Weekly)
- M3-99-15721 Fiber Scope Inspection of Service Water Side of Containment Recirculation Pump Area Cooler Condenser Heat Exchanger (3HVQ*ACUS2B)

b. Observations and Findings

The inspector reviewed surveillance procedure, SP 3614F.9 (Revision 2), confirming adequate discussion and control of certain pieces of material and test equipment utilized in the conduct of the surveillance test. Two condition reports, CRs M3-99-4208 and 4209, were issued to document questions regarding valve stroke time limits. The inspector determined that the issue of valve "ISI Min/Max" stroke time deviations was handled separately from the "Design Limit" criteria, as was adequately discussed in the Surveillance Procedure instructions. The inspector discussed with the on-shift operators the usage of video camera equipment in the conduct of the surveillance activities. The inspector verified that sufficient procedural guidance and detail is specified to adequately control the practice of video timing valve strokes, but also noted the option for using a quality assurance (QA) stopwatch, at the discretion of the Shift Manager, for the conduct of second-stroke tests.

The inspector observed troubleshooting activities following the failure of the turbine, Number 5 combined intermediate stop and intercept valve (CIV) to fully stroke during the weekly performance of SP 3623.2-1. Operators entered applicable TS 3.3.4. Effective communication was noted between operations, maintenance, instrumentation and control (I&C), and engineering personnel to plan and execute subsequent testing. Engineering personnel issued Memo No. MP-USE-99-029 to the shift manager documenting previous discussions with the turbine vendor which indicated that the turbine was designed such that it could be operated indefinitely with one CIV closed as long as no other operational concerns existed. The memo stated that preferred operation with one valve closed is two hours, but it may remain closed as long as reasonable efforts to restore it to operation are pursued. The prebrief for the retest of the affected CIV was given to involved personnel and focused on the actions to be performed by the various groups, communication, and contingencies. During the troubleshooting performance of the SP, the valve stroked as described by the surveillance procedure and no problems were detected in the field. Operators exited the TS LCO. The inspector determined that actions taken to this point were reasonable. In addition, the licensee planned to conduct this portion of the surveillance during day shift the following week, instead of on mids as is typical, to allow engineering and I&C personnel to support the activity. The inspector verified the testing was conducted as planned throughout the rest of the inspection period with no further problems identified.

The inspector also observed system restoration activities on the "B" train engineered safety features (ESF) building ventilation system, noting plant equipment operators appropriately using the procedures, self-checking, and independent verification controls for component positioning and tagging. With respect to the calibration of heat tracing equipment, the inspector noted that updated tags were posted on the backup panel (3HTS-PNL-F2) for the heat tracing of safety-related components and piping. The inspector had previously confirmed that the licensee had performed the calibration activities in September 1999, consistent with the checks and calibrations of the primary heat tracing panel (3HTS-PNL-F1) equipment.

c. Conclusions

Observed Unit 3 surveillance and maintenance activities were well controlled and conducted in accordance with approved work orders and procedures. Appropriate corrective actions were taken when unanticipated testing results were obtained.

U3 M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Evaluation and Control of Scaffolding

a. Inspection Scope (62707)

The inspector reviewed the work control procedures governing the erection, engineering evaluation, and control of scaffolding located in proximity to safety-related equipment. The field conditions for one scaffold were examined, along with the authorizing work documents, the in-place tagging, and the procedurally required scaffolding checklist and evaluation.

b. Observations and Findings

The inspector reviewed the Common Maintenance Procedure, C MP 720A (Revision 2), on “Scaffold Erection, Use and Removal” and the Unit 3 procedure, U3 WC 1 (Revision 2), on work management, which includes specific instructions on “Scaffolding” in Attachment 10. The inspector noted in Attachment 10 a “caution” statement indicating, “Seismic requirements to ensure OPERABILITY of Safety Related equipment include a minimum 2 inch shake space between the scaffold and Safety Related equipment ... “ and, “If shake space is less than 2 inches, supplementary instructions are required to ensure seismic interaction will not impact OPERABILITY of Safety Related equipment.”

During an inspection-tour of the main steam and feedwater valve building, the inspector examined a scaffold erected in proximity to a feedwater containment isolation valve, 3FWS*CTV41B. Tags were affixed to the scaffolding and documented the appropriate information, including the automated work order (AWO) for the scaffold erection, as well as the AWO for the maintenance activity that required the scaffolding to remain in place. The inspector noted that parts of the scaffold were closer than two inches to some of the safety-related components in the area; with one example of a safety-related main steam system pressure transmitter (3MSS*PT525) approximately one-half inch from the erected scaffolding tube steel.

The inspector reviewed the scaffolding erection work order, AWO M3 99 15231, noting that the scaffolding checklist and evaluation (Attachment 10.2) supplementary instructions recognized the two inch clearance criterion between the scaffold and safety-related equipment in the area. However, an engineering review following the post-installation walk-down noted that while the two inch criterion could not be met, the rigidity of the scaffolding, when shaken, was sufficient to prevent contact. The inspector questioned whether this post-installation engineering review was sufficient to meet the intent of the “seismic requirements” of procedure U3 WC 1. The inspector noted that a seismic induced hazards review, including visual inspection of the separation and clearances between installed components, was a design consideration documented in Specification SP-ME-810.

Further discussion with licensee engineering representatives revealed that the existing documentation regarding the potential effect of the subject scaffolding on safety-related components did not meet the intent of the procedural requirements and was not sufficient. The licensee issued condition report CR M3-00-0098 to document this discrepancy. The recommended corrective actions include more explicit details in the evaluation when the specified criteria are not met and contact with Design Engineering when deviations are identified. The inspector verified that the work requiring erection of the subject scaffolding had been completed and that the scaffold was scheduled for removal.

The inspector determined that failure to adequately document supplementary instructions for potential seismic interactions of scaffolding and plant equipment, when the “shake space is less than 2 inches”, represented a violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings”. However, based upon the licensee’s issuance of CR M3-00-0098 and planned corrective actions, noted above;

and also consistent with Section VII.B.1.a of the NRC Enforcement Policy, this Severity level IV violation is being treated as a Non-Cited Violation.

c. Conclusions

Review of the licensee's work control procedures governing the erection of scaffolding identified adequate controls and engineering directions. However, some Unit 3 scaffolding was identified by NRC field inspection to be in violation of the procedural provisions for ensuring that seismic interactions would not impact the operability of nearby safety-related equipment. This failure to follow procedures is being treated as a **Non-Cited Violation (NCV 50-423/99-14-08)**.

U3 M8 Miscellaneous Maintenance Issues

M8.1 (Closed) IFI 50-423/96-09-15; Millstone Unit 3 Safeguards Equipment Room Ventilation & Coolers Excluded From High Risk Without Completing Room Heat Load Calculations

a. Inspection Scope (92902)

The inspectors reviewed the licensee's response and related actions to address Inspector Follow-up Item (IFI) 50-423/96-09-15. This IFI was opened to review Unit 3 safeguards equipment room ventilation and coolers which had been excluded from being classified as high risk significant systems without completing room heat load calculations.

The inspectors conducted in-office and onsite reviews of the IFI. This review included a review of Unit 3 engineering and maintenance rule procedures, associated engineering evaluations/memorandums, work activities, and corrective action documents in the licensee's corrective action process. In addition, these items were discussed with safety analysis engineers and the affected system engineers.

b. Observations and Findings

The licensee completed associated heat load calculations and technical evaluations summarized in Engineering Record Correspondence 25203-ER-99-1001. The following system/functions were recommended reclassified as risk significant: Auxiliary Building heating ventilation and air conditioning (HVAC) system for reactor plant chilled water and charging systems; Control Building HVAC and Chilled Water for the East and West Switchgear Rooms; ESF Building HVAC; and Intake Structure Ventilation for Service Water. The Maintenance Rule Expert Panel met on September 23, 1999, and revised the risk significance determination and performance measures for the above systems with the exception of the Control Building HVAC and Chilled Water for the East and West Switchgear Rooms (expert panel meeting minutes, memo PEG-99-019).

The licensee determined that the initial heat load calculation and technical evaluation for the Control Building HVAC and Chilled Water for the East and West Switchgear Rooms had been overly conservative based on estimated heat loads. The system engineer prepared a technical evaluation based on more realistic/actual heat loads in these areas

(M3-EV-99-0114). The safety analysis engineering group will prepare a calculation to support the results of the technical evaluation with an estimated completion date of January 31, 2000, and the expert panel is scheduled to review the results of the technical evaluation and calculation by February 28, 2000 (CR M3-99-1285, AR # 99006693, assignments 9 and 10).

c. Conclusion

The licensee's action to re-evaluate the risk significance of the Unit 3 safeguards equipment room ventilation and coolers and to establish appropriate performance measures for these areas was acceptable and complete with the exception of the East and West Switchgear Rooms. This remaining item to reverify the heat loads and confirm risk significance for the heating, ventilation and air conditioning system will be closed based on the licensee tracking completion of all corrective actions associated with CR M3-99-1285, which is scheduled for completion February 28, 2000. **IFI 50-423/96-09-15** is **closed**.

M8.2 (Closed) IFI 50-423/97-80-05; Balancing Reliability and Unavailability

a. Inspection Scope (92902)

The inspectors reviewed the licensee's response and related actions to address Inspector Follow-up Item (IFI) 50-423/97-80-05. This IFI was opened to review the licensee's ability to effectively balance reliability and unavailability after the unit had been operating for a period of time and the licensee had an opportunity to gather real plant data related to system performance.

The inspectors conducted in-office and onsite reviews of the IFI. This review included a review of Unit 3 engineering and maintenance rule procedures, associated engineering evaluations/memorandums and corrective actions documents in the licensee's corrective action process. In addition, the item was discussed with system engineers and the maintenance rule coordinators.

b. Observations and Findings

The item on balancing reliability and unavailability is closed based on a review of the completed Unit 2 & 3 maintenance rule periodic assessment reports dated July 10, 1998, and the joint (Units 2 & 3), "Periodic Assessment of Maintenance Rule Program" report, dated December 17, 1999, which appropriately addressed balancing reliability and unavailability as defined in 10 CFR 50.65 (a)(3). Balancing reliability and unavailability program requirements were described in Attachment 1 to Engineering Department Instructions (EDI) No. 30740, "Maintenance Rule Periodic Assessment". Several items remained open from the Units 2 & 3 past periodic assessments completed in May 1998, and are being tracked under CRs identified in Attachment 8-1 of the recently completed periodic assessment dated December 17, 1999.

c. Conclusion

The licensee appropriately completed two periodic assessments for each unit which addressed balancing reliability and unavailability as described in 10 CFR 50.65(a)(3). The licensees process for balancing reliability and unavailability was sound. **IFI 50-423/97-80-05** is **closed**.

M8.3 (Closed) IFI 50-423/98-02-03; Millstone Unit 3 Evaluation and Resolution of Condition Report M3-98-1976 on High Confidence Level of Reliability Performance Measures

a. Inspection Scope (92902)

The inspectors reviewed the licensee's response and related actions to address Inspector Follow-up Item (IFI) 50-423/98-02-03. Both the Millstone Unit 3 NRC Operational Safety Team Inspection and the Maintenance Rule baseline team inspection (May 1998) had concluded that a number of high risk significant SSCs had reliability performance measures that were set too high for Unit 3. This IFI noted that the licensee had identified the need to review Unit 3 reliability performance criteria for all high risk significant systems, as indicated in Condition Report (CR) M3-98-1976 (April 15, 1998). The review of the performance measures had not started at the time of the maintenance baseline team inspection in May 1998, therefore, this IFI had been opened to verify the licensees's review and resolution of this item which had a scheduled completion date of October 16, 1998.

The inspectors conducted onsite reviews of the IFI. This review included a review of Unit 3 engineering and maintenance rule procedures, associated engineering evaluations/memorandums and corrective actions documents in the licensee's corrective action process. In addition, the item was discussed with the site supervisor for PRA and the maintenance rule coordinator for Unit 3.

b. Observations and Findings

The inspectors noted that the licensee had originally used the EPRI guidance of 1% (measure of confidence level) to determine the acceptable reliability performance measures for risk significant systems. Late in 1997, subsequent to Millstone 3 calculations, standard industry practice became the use of EPRI guidance of 5% (measure of confidence level). Since the 5% method is more conservative, a recalculation could result in fewer functional failures (more conservative performance criterion) being allowed for risk significant systems. This method (i.e., EPRI guidance of 5%) was also endorsed by the NRC staff as one of two acceptable methods of determining performance measures in "Supplemental Maintenance Rule Inspection Guidance, Section VI, Inspection Guidance for Reliability and PRA Specialists," dated February 2, 1998.

The inspectors reviewed PRA memo number NE-98-SAB-127, "Maintenance Rule Functional Failure Performance Criteria Validation," dated August 31, 1998, which recommended that numerous performance measure values in various risk significant SSCs be revised to be in line with the current and more conservative industry standards. The basis for these recommended changes was "NUSCO PSA Guideline No. 6 (dated October 7, 1997), Technical Basis for Functional Failure Count Performance Criteria".

At the time of the inspection, this guideline based on EPRI guidance of 5% (i.e., to determine the acceptable reliability performance measures for high risk significant systems) had been adopted by the licensee for Unit 2 but had not been fully implemented for Unit 3.

The inspectors noted that for at least one example (Station Blackout (SBO) Diesel), the recommended PRA/industry based standard criteria of less than two functional failures had been exceeded. The failures occurred during quarterly preventive maintenance (PM) for the 125 volt SBO diesel battery bank (CR M3-98-3650) and following restoration from tagging for PM (CR M3-99-1106). The inspectors reviewed the details of these two functional failures and the licensee's corrective actions and determined that no operability issues currently exist regarding these failures. However, had the new performance measures been adopted, the licensee would have been obligated to place the diesel in an (a)(1) status and establish appropriate goals in the general time frame of April 13, 1999, following the second functional failure. Furthermore, for approximately 14 high risk significant SSCs, the PRA/industry recommended performance measures had never been adopted as of the end date of this inspection (December 14, 1999), approximately 15 months after issuance of the PRA memo (NE-98-SAB-127). The licensee initiated CR M3-99-3966 the week before this inspection, when the expert panel met and was not able to resolve this issue.

Also, the inspectors discussed with the Unit 3 maintenance rule coordinator the method the licensee had used for establishing performance measures for the emergency diesel generators (EDGs) and SBO diesel. The Unit 3 maintenance rule coordinator indicated that these performance measures had been established based on suggested trigger values recommended in NUMARC 87-00. The inspectors noted that in Generic Letter 94-01, "Removal of Accelerated Testing and Special Reporting Requirements for Emergency Diesel Generators," dated May 31, 1994, that the staff had voiced a concern over use of the trigger values identified in NUMARC 87-00 for the purposes of monitoring EDG performance.

This area is unresolved pending further NRC evaluation of whether a violation of 10 CFR 50.65(a)(1) and (a)(2) occurred with respect to: (1) the licensee's methods for establishing performance measures for high risk significant SSCs for Unit 3; (2) failure of the licensee to place the SBO Diesel in an (a)(1) status and to establish appropriate goals in the general time frame of April 13, 1999 following the second functional failure; (3) the licensee's method of establishing performance measures for the emergency diesel generators (EDGs) and SBO diesel. **(Unresolved Item 50-423/99-14-09)**

c. <u>Conclusion</u>

This area is unresolved pending further NRC evaluation of whether a violation of 10 CFR 50.65(a)(1) and (a)(2) occurred with respect to: (1) the licensee's methods for establishing performance measures for high risk significant SSCs for Unit 3; (2) failure of the licensee to place the SBO Diesel in an (a)(1) status and to establish appropriate goals in the general time frame of April 13, 1999, following the second functional failure; (3) the licensee's method of establishing performance measures for the emergency diesel generators (EDGs) and SBO diesel **(Unresolved Item 50-423/99-14-09)**. **IFI 50-423/98-02-03** is **closed**.

U3.III Engineering

U3 E1 Conduct of Engineering

E1.1 Engineering Review of Component Corrosion

a. Inspection Scope (37551)

The inspector reviewed the licensee engineering evaluation and response to NRC questions regarding evidence of galvanic corrosion on some stainless steel valves in the safety injection portion of the residual heat removal (RHR) system.

b. Observations and Findings

The inspector discussed with the cognizant licensee system engineer the observation of the appearance of galvanic corrosion on four safety-related, manual drain valves located in the RHR vaults in the engineered safety features building. The four safety injection, globe valves (3SIL*V996 thru V999) are provided as leakage monitoring connections in the suction flow paths to the RHR pumps. Engineering review confirmed that the valve components are fabricated of stainless steel material and that the corrosion on the valve body, yoke and bolts is galvanic in nature.

The inspector reviewed a licensee memorandum (ME-WM-99-323), dated December 8, 1999, from the licensee's Material Engineering group, that evaluated the observed corrosion, its probable causes and impact, and potential solutions to prevent further degradation. It was determined that a boric acid solution created by small valve leaks coupled with condensation from piping above was sufficient to electrolytically cause the galvanic corrosion between the different stainless steel material parts making up the subject valves. The structural integrity of these valves was not compromised by this condition, based upon an assumed corrosion rate consistent with the boric acid concentrations and conservative moisture and temperature conditions. Since similar valves with insulated piping above them did not exhibit corrosion, a recommendation was made to insulate the bare pipe to eliminate the moist atmosphere and thus one electrolytic cause of the corrosion.

c. Conclusions

The licensee system engineer appropriately conducted follow-up of observed corrosion on some safety-related Unit 3 valves. Material engineers evaluated the as-found conditions in the plant, determined that the immediate, adverse safety impact was minimal, and recommended a solution to eliminate further corrosion as a longer term corrective action. Overall licensee response to this issue was good.

E1.2 Year 2000 Project Readiness Review

Please refer to Section U2.E1.1 of this report for a discussion of this area.

U3 E2 Engineering Support of Facilities and Equipment

E2.1 Turbine Driven Auxiliary Feedwater Pump Discharge Isolation Valves Fail to Stroke

a. Inspection Scope (37551, 71707, 62707)

On the evening of December 20, and early morning on December 21, 1999, the "A" and "D" turbine driven auxiliary feedwater (TDAFW) pump discharge isolation valves (3FWA*HV36A/D) failed to stroke closed during routine surveillances. The inspector discussed the failures with operations and engineering personnel; observed licensee troubleshooting activities in the control room and in the plant; and reviewed applicable design documentation, procedures, and prints.

b. Observations and Findings

The licensee issued CRs to document the failure of the "A" isolation valve to stroke closed (CR M3-99-4132) and the slow closure of the "D" TDAFW pump discharge isolation valve (CR M3-99-4135). Operators correctly entered TS 3.6.3 for containment isolation valves and closed and de-energized a manual valve in each line upstream of the subject isolation valves, as required by the action statement. Another safety function for these valves is to open to allow AFW flow to the steam generators. Therefore, with these manual valves closed, the TDAFW system to these generators was inoperable. As a result, operators properly entered TS 3.7.1.2.a, which has a 72 hour shutdown action statement for this condition.

The inspector observed effective communication among engineering, operations, maintenance, and work planning personnel to troubleshoot these valves in a timely manner. Subsequent field testing was well controlled and performed in accordance with approved procedures and work orders.

Engineering personnel discussed the observed problems with the valve vendor, Target Rock. The vendor confirmed that these valves are meant to function with a differential pressure across them. The testing performed in the surveillance is essentially static, thereby making closure difficult. (Both valves closed in subsequent testing at much greater times than allowed in the surveillance.) The valves are normally open and receive no automatic signal. The surveillance test specifies stroking the valves and timing the stroke for Inservice Testing (IST) for the purpose of monitoring and trending any valve degradation. There is no stroke time required for the valves by the design basis, as stated in the FSAR. The licensee and vendor agreed that ideally these valves should be tested with a differential pressure across them, as would typically be seen during accident conditions. The licensee initiated an action item in their corrective action plan to develop an alternate test method for these valves ("A", "B", "C", and "D").

Notwithstanding the design-basis valve function, discussed above, these valves are also containment isolation valves (CIVs), which operators would need to be able to close with or without a differential pressure across them. Therefore, to declare the valves operable, the licensee needed to be able to also address the CIV function. The licensee prepared operability determinations (ODs), MP3-037-99 and MP3-038-99, for these valves. The ODs thoroughly discuss the function and design of the valves and address the containment isolation function. It was demonstrated that operators can “bump” the valves closed from the control room by manipulating the power provided to the valves’ solenoids at the controllers. The inspector noted that caution tags, identifying this condition to the operators and providing such direction, have been placed at the controls for all four TDAFW pump discharge isolation valves. In addition, another action item was created to modify the applicable procedures to alert operators to this operation of the valves, if needed. The inspector verified that the identified problems and licensee corrective actions would not adversely impact the safety-related “open” function of the valves.

c. Conclusions

Unit 3 personnel properly control and conducted troubleshooting activities for the “A” and “D” turbine driven auxiliary feedwater (TDAFW) pump discharge isolation valves’ failure to close on December 20, 1999. Operators properly entered and complied with applicable TS LCOs for containment isolation and auxiliary feedwater. Operability Determinations written to address the issue provided a logical basis for operability of the valves for the AFW and containment isolation functions. Caution tags on the main control boards provide operators important information regarding operation of the valves if problems are encountered during future manual valve manipulation.

U3 E8 Miscellaneous Engineering Issues

E8.1 (Closed) Violation 50-423/98-81-01; Fire Barrier between the Unit 3 Cable Spreading Room and the Unit 3 Control Room

a. Inspection Scope (37550, 92700, 92903)

The inspector reviewed the licensee’s corrective actions to address Violation (VIO) 50-423/98-81-01.

b. Observations and Findings

Violation 50-423/98-81-01 involved a failure to provide an adequate fire barrier between the Unit 3 cable spreading and control rooms, as a result of not protecting certain fire barrier support steel columns from the effects of an exposed fire in the cable spreading room.

The licensee responded to the violation in a Northeast Nuclear Energy letter, B87279, dated June 22, 1998. The licensee’s corrective actions included engineering calculations that verified the 3-hour rating of the cable spreading room ceiling. This issue was entered into the licensee’s corrective action process as Condition Report M3-98-1332.

The licensee's corrective actions in response to the violation were determined to be acceptable. Violation 50-423/98-81-01 is closed.

c. Conclusions

The licensee's corrective actions to ensure the 3-hour fire rating of the Unit 3 cable spreading room ceiling, in response to an NRC violation were acceptable. Therefore, **Violation 50-423/98-81-01** is **closed**.

E8.2 (Closed) Violation 50-423/98-81-02; Multiple High Impedance Faults during a Postulated Control Room Fire

a. Inspection Scope (37550, 92700, 92903)

The inspector reviewed the licensee's corrective actions to address Violation (VIO) 50-423/98-81-02.

b. Observations and Findings

Violation 50-423/98-81-02 involved the failure of the licensee to ensure that certain vital alternating current power panels were not susceptible to multiple high impedance faults (MHIF) which could result in blowing the main power supply fuses.

The licensee responded to the violation in a Northeast Nuclear Energy letter, B17279, dated June 22, 1998. The licensee's corrective actions included drawing changes, panel modifications (including panel bypass switches), and engineering calculations. The engineering calculations verified incoming 150 ampere fuses for vital panels and 40 ampere fuses for non-vital panels would not blow due to MHIF. This issue was entered into the licensee's corrective action process as Condition Report M3-97-4684.

The licensee's corrective actions in response to the violation were determined to be acceptable. Violation 50-423/98-81-02 is closed.

c. Conclusions

In response to an NRC violation, the licensee initiated adequate corrective actions to ensure certain vital, alternating current, power panels were not susceptible to multiple high impedance faults. Therefore, **Violation 50-423/98-81-02** is **closed**.

E8.3 (Closed) Violation 50-423/98-206-04; Operator Performance Time to Isolate a Design Basis Steam Generator Tube Rupture

a. Inspection Scope (37550, 92700, 92903)

The inspector reviewed the licensee's corrective actions to address Violation (VIO) 50-423/98-206-04.

b. Observations and Findings

Violation 50-423/98-206-04 involved a failure to implement prompt corrective actions regarding assumed operator performance time to isolate a steam generator tube rupture (SGTR).

The licensee responded to the violation in a Northeast Nuclear Energy letter, B817161, dated June 26, 1998. The licensee's corrective actions included engineering calculations that verified the SGTR assumptions. SGTR scenario data was forwarded to the NRC in Northeast Nuclear Energy letter, B816020, verifying that an overall crew response to a postulated SGTR would not include a steam generator overfill condition. This issue was entered into the licensee's corrective action process as Condition Reports M3-98-2746 and M3-96-0875.

The licensee's corrective actions in response to the violation were determined to be acceptable. Violation 50-423/98-206-04 is closed.

c. Conclusions

The licensee's corrective actions to ensure appropriate operator actions during a postulated steam generator tube rupture, in response to an NRC violation, were acceptable. Therefore, **Violation 50-423/98-206-04** is **closed**.

E8.4 (Closed) Violation 50-423/98-207-15; Material, Equipment and Parts List Components

a. Inspection Scope (37550, 92700, 92903)

The inspector reviewed the licensee's corrective actions to address Violation (VIO) 50-423/98-206-04.

b. Observations and Findings

Violation 50-423/98-207-15 involved a failure to perform specific Material, Equipment and Parts List (MEPL) maintenance work and/or purchase history reviews. This resulted in non-safety related parts being procured and installed in American Society of Mechanical Engineers (ASME) components.

The licensee responded to the violation in a Northeast Nuclear Energy letter, B817361, dated July 17, 1998. The licensee's corrective actions included operability determinations and engineering calculations that verified the operability of each of the affected ASME components. Additional corrective actions included MEPL procedure and process changes. This issue was entered into the licensee's corrective action process as Condition Reports M3-98-3111, 1806, 1807 and 2667.

The licensee's corrective actions in response to the violation were determined to be acceptable. Violation 50-423/98-207-15 is closed.

c. Conclusions

The licensee's corrective actions to ensure appropriate MEPL maintenance work and/or purchase history reviews, in response to an NRC violation, were acceptable. Therefore, **Violation 50-423/98-207-15** is **closed**.

IV Plant Support

(Common to Unit 2 and Unit 3)

S1 Conduct of Security and Safeguards Activities

a. Inspection Scope (81700)

Determine whether the conduct of security and safeguards activities met the licensee's commitments in the NRC-approved security plan (the Plan) and NRC regulatory requirements. The security program was inspected during the period of December 6-9, 1999. Areas inspected included: Access Authorization (AA) program; alarm stations; communications; and protected area (PA) access control of personnel and packages.

b. Observations and Findings

Access Authorization Program. The AA program was reviewed to verify implementation was in accordance with applicable regulatory requirements and Plan commitments. The review included an evaluation of the effectiveness of the AA procedures, as implemented, and an examination of AA records for ten individuals. Records reviewed included both persons who had been granted and had been denied access. The AA program, as implemented, provided assurance that persons granted unescorted access did not constitute an unreasonable risk to the health and safety of the public. Additionally, access denial records and applicable procedures were reviewed to verify that appropriate actions were taken when individuals were denied access or had their access terminated.

Alarm Stations. Operations of the Central Alarm Station (CAS) and the Secondary Alarm Station (SAS) were reviewed. Both alarm stations were determined to be equipped with appropriate alarms, surveillance and communications capabilities. The inspector interviewed the alarm station operators and found them knowledgeable of their duties and responsibilities. Observations and interviews also verified that the alarm stations were continuously manned, independent and diverse so that no single act could remove the plant's capability for detecting a threat and calling for assistance. The alarm stations did not contain any operational activities that could interfere with the execution of the detection, assessment and response functions.

Communications. Document reviews and discussions with alarm station operators and response force members determined that there was a problem with the security radio system. The radio system had recently been replaced with a new system in an attempt to eliminate or minimize the number of areas in the plant where hand-held radios could not transmit or receive. However, the new radio system increased, instead of decreased, the number of areas where the radios could not be used. The licensee had identified this problem and was attempting to resolve this issue since effective communications are critical to the security organization meeting its regulatory responsibility. The licensee issued Condition Report M3-99-4032 to address this issue and pending resolution of the problem, alternate methods of communications have been implemented.

Protected Area Access Control of Personnel and Hand-Carried Packages. On December 7 and 8, 1999, during peak activity periods, personnel and package search activities were observed at the personnel access portal. Positive controls were determined to be in place to ensure only authorized individuals were granted access to the Protected Area (PA) and that all personnel and hand-carried items entering the PA were properly searched.

c. Conclusions

The licensee was conducting its security and safeguards activities in a manner that protected public health and safety. This portion of the program met the licensee's commitments and NRC requirements. A weakness was identified in the effectiveness of the security communications system. This weakness has been entered in the licensee's corrective action program.

S2 Status of Security Facilities and Equipment

a. Inspection Scope (81700)

Areas inspected were Protected Area (PA) assessment aids, PA detection aids and personnel search equipment.

b. Observations and Findings

Assessment Aids. On December 7 and 8, 1999, the effectiveness of the assessment aids was evaluated by observing the PA perimeter on closed circuit television (CCTV) in the Central Alarm Station (CAS). The evaluation of the assessment aids was accomplished by observing, on CCTV, a security force member (SFM) performing a perimeter patrol. The assessment aids generally had good picture quality, view and zone overlap. Additionally, to ensure Plan commitments were satisfied, the licensee had procedures in place requiring the implementation of compensatory measures in the event the alarm station operator was unable to properly assess the cause of an alarm.

PA Detection Aids. On December 7 and 8, 1999, while observing the assessment aids, testing was also observed of selected intrusion detection zones in the plant protected area. The appropriate alarm was generated in each zone for each test. Through observations and review of the testing documentation associated with the equipment repairs, the inspector verified that repairs were made in a timely manner and that the equipment was functional and effective, and met the commitments in the Plan.

Personnel and Package Search Equipment. On December 8, 1999, both the routine use and the daily operational testing of the licensee's personnel and package search equipment were observed. Personnel search equipment was being tested and maintained in accordance with licensee procedures and the Plan, and personnel and packages were being properly searched prior to protected area access.

Observations and procedural reviews determined that the search equipment performed in accordance with licensee procedures and Plan commitments.

c. Conclusions

The licensee's security facilities and equipment were determined to be well maintained and reliable and were able to meet the licensee's commitments and NRC requirements.

S3 Security and Safeguards Procedures and Documentation

a. Inspection Scope (81700)

Areas inspected were implementing procedures and security event logs.

b. Observations and Findings

Security and Program Procedures. Review of selected security program implementing procedures, associated with personnel search, vehicle search and equipment testing verified that the procedures were consistent with the Plan commitments.

Security Event Logs. The Security Event Logs for the previous twelve months were reviewed. Based on this review, and discussion with security management, it was determined that the licensee analyzed, tracked, addressed and documented safeguards events. Review of the logs disclosed that control of Safeguards information (SGI) continues to be a problem. Since the beginning of 1999, there have been seven events that were logged involving control of SGI. The licensee has consolidated these events into one corrective action. This issue is being addressed in Condition Report M3-99-4051.

c. Conclusions

Security and safeguards procedures and documentation were being properly implemented. Event Logs were being properly maintained and used to analyze, track, and address safeguards events.

S4 Security and Safeguards Staff Knowledge and Performance

a. Inspection Scope (81700)

Area inspected was security staff requisite knowledge.

b. Observations and Findings

Security Force Requisite Knowledge. A number of security force members (SFMs) were observed in the performance of their routine duties. These observations included alarm station operations, personnel and package searches, and exterior patrol alarm response. Additionally, SFMs were interviewed and based on the responses to questioning, it was determined that the SFMs were knowledgeable of their responsibilities and duties, and could effectively carry out their assignments.

Response Capabilities. Discussions with the training staff and review of documentation of contingency response drills and critiques disclosed that the licensee is conducting drills. However, few drills are being documented. The overall effectiveness of the drill program could not be evaluated due to the lack of documentation. The licensee is addressing this issue in Condition Report M3-99-4034.

c. Conclusions

The SFMs adequately demonstrated that they had the requisite knowledge necessary to effectively implement the duties and responsibilities associated with their position. Response capabilities could not be evaluated due to a lack of documentation for drills, which is being addressed by the licensee's corrective action program.

S5 Security and Safeguards Staff Training and Qualification

a. Inspection Scope (81700)

Areas inspected were security training and qualifications and training records.

b. Observations and Findings

Security Training and Qualifications. On December 8, 1999, Training & Qualification records of eight security force members (SFMs) were reviewed. The results of the review indicated that these personnel met the annual requalification requirements in the approved Training & Qualifications (T&Q) plan.

Training Records. Through review of training records, it was determined that the records contained a certification that the training had been conducted, but no supporting documentation was available. The weakness in the training records is being addressed in Condition Report M3-99-4034.

c. Conclusions

Security force personnel were being trained in accordance with the requirements of the T&Q Plan. Training documentation was weak and is being addressed in the licensee's corrective action program.

S6 Security Organization and Administration

a. Inspection Scope (81700)

Areas inspected were management support and staffing levels.

b. Observations and Findings

Management Support. Review of program implementation since the last program inspection disclosed that adequate support and resources continued to be available to ensure effective program implementation.

Staffing Levels. The total number of trained security force members (SFMs) immediately available on shift met the requirements specified in the Plan and implementing procedures.

c. Conclusions.

The level of management support was adequate to ensure effective implementation of the security program, and was evidenced by the allocation of resources to support programmatic needs.

S7 Quality Assurance in Security and Safeguards Activities

a. Inspection Scope (81700)

Areas inspected were audits, problem analyses, corrective actions and effectiveness of management controls.

b. Observations and Findings

Audits. The 1999 Quality Assurance (QA) Security Program Audit was reviewed. Review of the audit disclosed that it was comprehensive in scope and depth.

Problem Analyses. A review of data derived from the security department's self-assessment program indicated that potential weaknesses were being properly identified, tracked, and trended.

Corrective Actions. Review of corrective actions implemented by the licensee, in response to the QA audits and self-assessment program, disclosed that all corrective actions had been implemented.

Effectiveness of Management Controls. The licensee had programs in place for identifying, analyzing and resolving problems. They include the performance of annual QA audits and a departmental self-assessment program.

c. Conclusions

The review of the licensee's audit program indicated that the security program audits were comprehensive in scope and depth, that findings were reported to the appropriate level of management, and that the program was being properly administered. In addition, a review of the documentation applicable to the security self-assessment program indicated that the program was being implemented to identify and resolve potential weakness.

V. Management Meetings

X1 Exit Meeting Summary

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

X3 Management Meeting Summary

On December 15, 1999, a public meeting was held at Millstone Station between NU and the NRC Millstone Assessment Panel to discuss Enhanced Performance System, Emergency Preparedness, Unit Status, Backlog Reduction, and Safety Conscious Work Environment. Slides from the meeting are attached to this report.

INSPECTION PROCEDURES USED

IP 37550	Engineering
IP 37551	Onsite Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Program
IP 71707	Plant Operations
IP 71750	Sustained Control Room and Plant Observation
IP 81700	Physical Security Program for Power Reactors
IP 92700	Onsite Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902	Follow-up Maintenance
IP 92903	Follow-up Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-336/99-14-01	NCV	Failure to place RPS into a Maintenance Rule (a)(1) status
50-336/99-14-02	NCV	Failure to establish and implement adequate testing of the safety injection recirculation header (related to LER 50-336/98-20-00)
50-336/99-14-03	NCV	Failure to establish and implement adequate CAR fan testing (related to LER 50-336/98-23-00)
50-336/99-14-04	NCV	Failure to establish and implement adequate testing of certain check valves (related to LER 50-336/98-25-00)
50-336/99-14-05	NCV	Failure to adequately establish and implement design controls associated with safety-related cable tray spacing and placement (related to LER 50-336/98-18-00 & 01)
50-336/99-14-06	NCV	Failure to adequately establish and implement design controls to ensure that the safety-related design bases for containment pressure instruments were correctly translated into specifications, drawings and procedures (related to LER 50-336/98-24-00)
50-336/99-14-07	NCV	Failure to adequately establish and implement design controls for the pressurizer spray line design criteria (related to LER 50-336/98-26-00)
50-423/99-14-08	NCV	Failure to adequately document supplementary instructions for potential seismic interactions of scaffolding and plant equipment
50-423/99-14-09	URI	Adequacy of performance measures for high risk significant SSCs

Closed

The NCVs opened above are closed.

50-336/98-02-01	IFI	Implementation Maintenance Rule Issues: (1) System Engineer Determination of Maintenance Rule Functional Failures and (2) Licensee's Action to Clarify Definitions of Functional Boundaries Between Interfacing and Overlapping Systems
50-336/98-02-02	IFI	Implementation Maintenance Rule Issues: (1) Review Effectiveness of Licensee's Maintenance and Performance Monitoring; (2) Balancing Reliability and Unavailability and (3)&(4) Review Operators Knowledge and Use of On-Line Maintenance Risk Assessment
50-336/98-206-02	URI	Safety Parameter Display System
50-423/96-09-15	IFI	Millstone 3's Safeguards Equipment Room Ventilation & Coolers Excluded From High Risk Without Completing Room Heat Load Calculations
50-423/97-80-05	IFI	Balancing Reliability and Unavailability
50-423/98-02-03	IFI	Millstone 3's Evaluation and Resolution of Condition Report M3-98-1976 on High Confidence Level of Reliability Performance Measures
50-423/98-81-01	VIO	Fire Barrier between the Unit 3 Cable Spreading Room and the Unit 3 Control Room

50-423/98-81-02	VIO	Multiple High Impedance Faults during a Postulated Control Room Fire
50-423/98-206-04	VIO	Operator Performance Time to Isolate a Design Basis Steam Generator Tube Rupture
50-423/98-207-15	VIO	Material, Equipment and Parts List Components

<u>Discussed</u>

None

<u>The following LERs were also closed during this inspection:</u>

LER 50-336/98-16-00	Safety Injection System Administrative Controls
LER 50-336/98-18-00 & 01	Spacial Separation of Redundant Cables
LER 50-336/98-19-00	Auxiliary Feedwater Regulating Valve Response to a High Energy Line Break
LER 50-336/98-20-00	Safety Injection Recirculation Header Inservice Visual Inspection Requirements
LER 50-336/98-23-00	Containment Air Recirculation Fan Testing
LER 50-336/98-24-00	Potential Containment Leakage Path
LER 50-336/98-25-00	Check Valve Testing Requirements
LER 50-336/98-26-00	Pressurizer Spray Line Fatigue Limits
LER 50-336/99-011-00	Exceeding the Thermal Reactor Power Limit

LIST OF ACRONYMS USED

AFW	auxiliary feedwater
ALARA	as low as is reasonably achievable
ASME	American Society of Mechnical Engineers
AWOs	automated work orders
CAR	containment air recirculation
CAS	central alarm system
CCTV	closed circuit television
CIV	combined intermediate stop and intercept valve
CRAC	control room air conditioning
CRED	Condition Report Engineering Disposition
EDI	Engineering Department Instruction
ESF	engineered safety features
FDSSS	flow dependent setpoint selector switch
FSAR	Final Safety Analysis Report
HP	health physics
HVAC	heating ventilation and air conditioning
I&C	instrumentation and control
IEEE	Institute of Electrical Electronic Engineers
IFI	inspector follow-up
IST	inservice testing
LCOs	limiting conditions for operations
LER	Licensee Event Report
LOCA	loss of coolant accident
MEPL	Material Equipment and Parts List
MHIF	multiple high impendance faults
MRFF	Maintenance Rule Functional Failures
OD	operability determinations
PA	protected area
PRA	probabilistic risk assessment
QA	quality assurance
QSS	quench spray system
RBCCW	reactor building closed cooling water
RCAs	radiological control areas
RCP	reactor coolant pump
RHR	residual heat removal
RPS	reactor protection system
SAS	secondary alarm system
SBO	station blackout
SIT	safety injection tanks
SFM	security force member
SGI	safeguards information
SGTR	steam generator tube rupture
SI	safety injection
SPDS	safety parameter display system
SR	surveillance requirement
SSC	structure, system, or component

T&Q	training and qualification
TDAFW	turbine driven auxiliary feedwater
the Plan	NRC-approved physical security plan
TM/LP	thermal margin/low pressure
TS	technical specification
URI	unresolved item
VIO	violation
VT	visual testing

NU/NRC MILLSTONE ASSESSMENT PANEL PUBLIC MEETING

ENHANCED PERFORMANCE SYSTEM, EMERGENCY PREPAREDNESS,

UNIT STATUS, BACKLOG REDUCTION, AND

SAFETY CONSCIOUS WORK ENVIRONMENT

DECEMBER 15, 1999

NORTHEAST UTILITIES BRIEFING SLIDES