March 10, 2000

Mr. S. 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 05000336/2000001 and 05000423/2000001

Dear Mr. Scace:

On February 14, 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.

Based on the results of this inspection, the NRC identified six Level IV violations of NRC requirements, one of which related to the Unit 3 design control inadequacy that resulted in the contamination of a containment sump that was required to be maintained clean. The remaining five examples were associated Unit 2 Licensee Event Reports that involve conditions that existed 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,

/RA/

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

Docket Nos. 05000336 and 05000423
License Nos. DPR-65 and NPF-49

Enclosure: NRC Combined Inspection Report 05000336/2000001 and 05000423/2000001

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M. H. Brothers, Vice President - Nuclear Operations
F. C. Rothen, Vice President - Nuclear Work Services
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U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos.:	05000336	05000423
Report Nos.:	200001	200001
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: January 4, 2000 - February 14, 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
B. E. Sienel, Resident Inspector, Unit 3
S. K. Chaudhary, Senior Reactor Engineer, DRS
K. M. Jenison, Senior Project Engineer, Region 1
J. D. Noggle, Senior Health Physicist, DRS
B. S. Norris, Senior Reactor Inspector, DRS

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

TABLE OF CONTENTS

EXECUTIVE SUMMARY
Millstone Nuclear Power Station
Combined Inspection 50-336/2000-01; 50-423/2000-01

Operations

- On January 27, 2000, when Unit 2 operators encountered problems restoring the sight-glass for the 2A main feedwater heater to service, operators cycled one of the sight-glass isolation valves. The valve manipulation initiated a feedwater heater level transient that was exacerbated by sluggish operation of the 2A feedwater heater level control system, which had also contributed to a previous reactor trip on May 25, 1999. As a result of an original design problem associated with the heater drain tank, the feedwater heater level transient developed into an unanticipated total loss of heater drain flow, a trip of one main feedwater pump, and a subsequent manual reactor trip based on decreasing steam generator water levels. The NRC found that the corrective actions implemented prior to power ascension were adequate to address the direct causes of the loss of main feedwater flow and the subsequent reactor trip. No violations of NRC requirements were identified. Licensee Event Report 50-336/2000-001-00 is closed. (Section U2.O1.2)

- At Unit 2, on February 11, 2000, operators appropriately initiated a manual reactor trip when two control rods dropped completely into the core during control rod testing. The licensee's corrective actions to address the causes of the dropped rods (i.e., a ground in a power switch module and a separate ground in a drive mechanism coil) were acceptable. When further testing identified degradation of components in the control rod power switch modules, equipment obsolescence hampered the licensee's ability to effectively resolve the resultant reliability problems due to difficulties in obtaining replacement parts. (Section U2.O1.3)

- About 25 minutes after the reactor trip, Unit 2 operators responded well to an unexpected cooldown and quickly restored pressurizer level. The NRC found that the licensee had closed the corrective action assignment addressing the cooldown without resolving the issue. Subsequently, the licensee determined that due to a deficient procedure, the controllers for steam supply valves for the moisture separator/reheaters were left in manual. As a result, the valves remained open after the reactor trip and operators were unnecessarily challenged by the cooldown. (Section U2.O1.3)

- NNECO evaluated the Wolf Creek event, in response to NRC GL 98-02, and determined that neither unit was susceptible to a similar type of scenario. The inspectors considered the evaluations to be adequate. (Sections U2.O7.1 and U3.O7.1)

- At Unit 3, operations personnel response to plant equipment problems and cold weather conditions was both timely and appropriate. A licensee event report was issued, and remains open, to document a measured low temperature condition in the service water system that was outside the design basis of the plant. The noted event was adequately evaluated with respect to the affected components' operability. Plant inspection-tours revealed housekeeping, equipment status, and tagging/lineup controls consistent with procedural provisions and system configurations being tracked by the operators on shift in the control room. (Section U3.O2.1)

Maintenance

- At Unit 2, the licensee identified in 1998 that historically, certain technical specification (TS) required surveillance tests had not been adequately performed. This is a violation of Unit 2 TS 4.3.2.1, Engineered Safety Feature Actuation System Instrumentation and 4.3.3.4, Meteorological Monitoring Instrumentation. The licensee's corrective actions were found acceptable. This violation is being treated as a Non-Cited Violation (NCV 50-336/2000-01-01). Licensee Event Report 50-336/98-08-00 is closed. (Section U2.M8.3)

- At Unit 2, in 1998, the licensee identified a historical condition involving the fact that a failure to establish a surveillance procedure did not verify that the enclosure building would maintain the negative pressure assumed in its design basis. During worst case conditions, this could have resulted in increased post accident leakage to the atmosphere from Unit 2 containment. The licensee's corrective actions were found acceptable. The failure to establish an adequate surveillance procedure for testing the enclosure building is a violation of Technical Specification 6.1.8.c. This violation is being treated as a Non-Cited Violation (NCV 50-336/2000-01-02). LER 50-336/98-010-00 is closed. (Section U2.M8.4)

- At Unit 3, the licensee implemented timely and effective corrective measures to restore system functionality in response to equipment problems, discovered during preventive maintenance activities, that could have prevented the start and continued operation of the Unit 3 station blackout (SBO) diesel generator during a hypothesized SBO event. The licensee also provided a sound, documented basis as to why the identified degraded conditions did not constitute a reportable event pursuant to regulatory requirements and related guidance. (Section U3.M2.1)

Engineering

- At Unit 2, in 1998, the licensee identified a historical condition involving the potential failure of the main feedwater isolation valves to fully close following a main steam line break which would have resulted in the Unit 2 containment exceeding its design pressure. This is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. The licensee's corrective actions were found acceptable. This violation is being treated as a Non-Cited Violation (NCV 50-336/2000-01-03). Licensee Event Report 50-336/98-011-00 is closed. (Section U2.E8.2)

- At Unit 2, in 1998, the licensee identified a historical shutdown cooling system configuration in which an inadvertent start of a HPSI pump could have resulted in the shutdown cooling system exceeding the pressure assumed in its design basis for approximately four minutes. This is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. The licensee's corrective actions were found acceptable. This violation is being treated as a Non-Cited Violation (NCV 50-336/2000-01-04). LER 50-336/98-013-00 is closed. (Section U2.E8.3)

- At Unit 2, in 1998, the licensee identified that historically, procedures and practices allowed the control room ventilation system doors and covers to be blocked open during power operations. This placed the control room ventilation system in a condition outside of its design basis. This is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. The licensee's corrective actions were found acceptable. This violation is being treated as a Non-Cited Violation (NCV 50-336/2000-01-05). Licensee Event Report 50-336/98-014-00 is closed. (Section U2.E8.4)

- At Unit 3, a review of the design change and licensing revision documents that support the current configuration of some non-safety instrument air system components revealed no deficiencies. This configuration does, however, result in the existence of an unnecessary "nuisance" annunciator in an alarmed state in the control room. The system engineer is currently evaluating various engineering options to remove this "nuisance" alarm for equipment not intended to be operated. (Section U3.E2.1)

- An inadequate design for part of the modification for the Unit 3 containment sump system resulted in contamination of one sump required to be maintained non-contaminated. This placed the plant in a condition outside of the design basis. The inadequate design was a violation of 10 CFR 50, Appendix B, Criterion III, which was categorized as Severity Level IV and treated as a Non-Cited Violation (NCV 50-423/2000-01-06). Licensee Event Report 50-423/99-07-00 is closed. (Section U3.E8.4)

Plant Support

- The licensee's investigations into the circumstances and probable causes of a reported 7.04 rem occupational dose to a personnel thermoluminescent dosimeter (TLD) in the second quarter of 1999 concluded that the dose to the badge was valid. However, the investigations further concluded that the dose was most likely caused by tampering and deliberate exposure of the TLD badge by an unknown person or persons and that the individual assigned the TLD badge had not received such an occupational dose. The licensee took corrective actions to preclude recurrence. No violations of regulatory requirements were identified. (Section R8.1)

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. On January 27, 2000, operators initiated a manual reactor trip from 100 percent power following a feedwater system transient that resulted in a loss of main feedwater flow and decreasing steam generator water levels. The plant responded normally to the trip, and operators stabilized the plant in Operational Mode 3, Hot Standby, at normal operating temperature and pressure. After identifying the problems with the feedwater heater and the heater drain tank control systems that led to the reactor trip, the licensee entered Operational Mode 2, Startup, and brought the reactor critical on January 29, 2000. Also on January 29, 2000, the licensee completed corrective actions to address the feedwater heater and heater drain tank control system problems and initiated a routine power ascension to 100 percent power. The plant reached 100 percent power on January 31, 2000.

On February 11, 2000, while performing control rod testing at 100 percent power, control rod number 65 unexpectedly dropped into the reactor. A short time later, with no control rod motion in progress, control rod number 63 dropped into the reactor. In accordance with operating procedures, the operators manually tripped the reactor. The plant responded normally to the trip, and operators stabilized the plant in Operational Mode 3, Hot Standby, at normal operating temperature and pressure. After concluding that control rod drive mechanism coil replacement was required, the licensee cooled down the plant and placed it in Operational Mode 5, Cold Shutdown, on February 13, 2000. At the completion of the inspection period on February 14, 2000, the plant remained in Operational Mode 5, Cold Shutdown.

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 and plant operational review committee meetings.

The inspector observed procedural adherence and conformance with technical specification requirements during routine operation at power. Operators responded well to two instances where plant conditions necessitated a reactor trip. These events are described in Sections O1.2 and O1.3 of this report.

O1.2 <u>(Closed) LER 50-336/2000-001-00; Manual Reactor Trip due to Low Steam Generator Level Following a Feedwater Heater Level Transient</u>

a. <u>Inspection Scope (93702/92700)</u>

The inspector reviewed the circumstances surrounding a manual reactor trip that was initiated due to a trip of one main feedwater pump and decreasing steam generator water levels. The main feedwater pump trip occurred following a feedwater heater level transient that resulted in a loss of heater drain pump flow. Inspection activities included an onsite review of the licensee's assessment of the cause of the feedwater system transients, corrective actions, and licensee event report (LER) 50-336/2000-001-00.

b. <u>Observations and Findings</u>

At 2:27 p.m. on January 27, 2000, operators manually tripped the Unit 2 reactor after experiencing feedwater heater level transients and observing decreasing steam generator water levels and a trip of one of two operating main feedwater pumps. Shortly after the reactor trip, the feedwater heater transient caused the second main feedwater pump to trip. The plant responded to the trip as designed with no complications. The inspector observed control room activities from shortly after the reactor trip and found that operator performance in placing the plant in a stable condition was good.

The events that led to the reactor trip began when operators returned the 2A feedwater heater sight glass to service following a leak repair. Because the sight glass shares the upper and lower level sensing lines with the level sensing device for the feedwater heater level control system, the evolution has the potential to initiate a feedwater heater level transient. When operators placed the sight-glass for the 2A heater in service using the operating procedure, the sight-glass filled with water. The operators believed that the excess-flow check valve at the top of the sight-glass had seated, which prevented the display of the actual water level. The operating procedure did not provide instructions to correct this condition. After discussing the problem with the Work Control Senior Reactor Operator, the operators decided to cycle the manual operator to unseat the excess flow check valve.

After cycling the valve, the water drained from the 2A heater sight-glass to the actual level, which induced a transient by causing the level controller to sense a false level in the 2A heater. Sluggish response of the normal level controller for the 2A heater, which contributed to a reactor trip on May 25, 1999, limited the ability of the controller to recover from the induced transient. A short time later, hot water from the 2A heater emptied to the heater drain tank through the sluggish normal level control valve. The increased temperature and pressure in the heater drain tank reduced flow from the 3A and 3B heaters to the tank, which caused water level in the 3A and 3B heaters to increase to the high level isolation setpoint and isolate the extraction steam inputs to the shell side of the heaters. When extraction steam was isolated to the 3A and 3B heaters, continued feedwater flow through the heater tubes cooled and depressurized the heaters. Because the heater drain tank was vented to the 3A and 3B heaters through valve 2-HD-104, the heater drain tank also depressurized resulting in insufficient suction head for the heater drain pumps. The loss of heater drain pump flow caused the operating main feedwater pumps to trip on low suction pressure. Operators initiated a manual reactor trip in response to the trip of the first main feedwater pump and the resultant decreasing steam generator water level.

The licensee identified the root cause of the reactor trip as a historic condition involving the control circuit that initiates isolation of the heater drain tank vent line to the 3A and 3B heaters by closing valve 2-HD-104. Design documents describing the function of the circuit stated that valve 2-HD-104 would close when any <u>one</u> of the following three conditions existed: (1) a turbine trip; (2) high water level in the shell side of the 3A feedwater heater; and (3) high water level in the shell side of the 3B feedwater heater. However, the circuit, as indicated on the circuit diagram and as configured in the field, required the three conditions to exist <u>simultaneously</u> in order to initiate isolation of valve 2 -HD-104. As a result of this design discrepancy, the heater drain tank unexpectedly depressurized when extraction steam was isolated to the 3A and 3B heaters due to high water levels.

As a corrective action to address the heater drain tank pressure control problem, the licensee modified the control scheme for valve 2-HD-104 to operate as described in the design documents. To address the sluggish behavior of the 2A heater level control system, the licensee inspected the normal level control valve for the 2A heater, replaced a component in the normal level control valve actuator (which improved the valve's stroke time), and performed an instrument loop calibration. The licensee also implemented administrative controls to preclude operation of the sight-glass isolation valves while the plant is operating at power. These actions were completed prior to placing the main turbine on-line, and the inspector found these corrective actions acceptable to support operation at power.

The NRC is evaluating the licensee's corrective actions for the reactor trip on May 25, 1999, the corrective actions for the reactor trip on January 27, 2000, and the relationship between the two events as part of the NRC's corrective action inspection. The inspection results will be documented in NRC Inspection Report 50-336/2000-03.

c. <u>Conclusions</u>

On January 27, 2000, when operators encountered problems restoring the sight-glass for the 2A main feedwater heater to service, operators cycled one of the sight-glass isolation valves. The valve manipulation initiated a feedwater heater level transient that was exacerbated by sluggish operation of the 2A feedwater heater level control system, which had also contributed to a previous reactor trip on May 25, 1999. As a result of an original design problem associated with the heater drain tank, the feedwater heater level transient developed into an unanticipated total loss of heater drain flow, a trip of one main feedwater pump, and a subsequent manual reactor trip based on decreasing steam generator water levels. The NRC found that the corrective actions implemented prior to power ascension were adequate to address the direct causes of the loss of main feedwater flow and the subsequent reactor trip. No violations of NRC requirements were identified. LER 50-336/2000-001-00 is **closed**.

O1.3 <u>Manual Reactor Trip in Response to Two Dropped Control Rods</u>

a. Inspection Scope (92702)

The inspector observed operator post-trip actions in response to two dropped control rods. The inspector also reviewed the licensee's actions to identify the cause of the dropped control rods.

b. Observations and Findings

While conducting planned monthly control rod testing on February 11, 2000, control rod No. 65 dropped completely into the reactor core from 180 steps withdrawn when operators attempted to insert the control rod five steps for testing. The licensee entered action statement (e) for Technical Specification 3.1.3.1, which applies when one or more control rods are misaligned from other control rods in their group by 20 steps or more. This action statement requires that the licensee reduce reactor thermal power to less than or equal to 70% power within one-hour. The operators initiated a power reduction by borating the reactor coolant system. With no control rod motion since it was tested 43 minutes earlier, control rod No. 63 unexpectedly dropped completely into the reactor core from 180 steps withdrawn. In response to the second dropped control rod, the operators immediately initiated a manual reactor trip, as specified by abnormal operating procedure (AOP) 2556, "CEA Malfunction."

The plant responded to the trip as designed with one minor complication. About 25 minutes after the reactor trip, the pressurizer level control system started all three charging pumps in response to an unexpected cooldown of the reactor coolant system (RCS) caused by steam flow to the moisture separator/reheaters. The inspector observed that operator performance was good in quickly determining the cause of the cooldown, isolating the steam flow, and restoring pressurizer level.

Each control rod was found to have a blown fuse on one of the three phases supplying power to their associated control rod drive mechanisms, which caused the rod to drop. The licensee initiated troubleshooting activities to identify the reason that two fuses blew in independent circuits. A maintenance history review identified no previous problems with control rod No. 63. Investigation of the control rod power switches found that contacts that apply latch current (i.e., a higher current initially applied to the coil to ensure that the gripper latches securely engage the control rod drive shaft) did not reopen following rod movement. The resultant high current for a period of about 43 minutes caused the blown fuse that interrupted all current to the upper gripper coil for control rod No. 63. Because the upper gripper holds the control rod when it is not in motion, loss of power to the upper gripper caused the control rod to drop. Later testing determined that a ground in a potentiometer in the power switch circuit had caused the contact to fail in the closed position.

With regard to control rod No. 65, the licensee had previously identified a ground in the leads for the control rod drive mechanism lower gripper coil. This ground resulted in a forced reactor shutdown on September 17, 1999, when control rod No. 65 slipped multiple instances during rod motion and became unrecoverable. The licensee repaired the ground by sliding an insulating material over the grounded lead. On January 29, 2000, the licensee had an indication that the repair was not completely successful when control rod No. 65 slipped from 112 steps to 108 steps withdrawn shortly after reactor startup. After the manual reactor trip on February 11, 2000, the licensee replaced the drive mechanism coil stack and the power switches for control rod No. 65. The licensee concluded that the previous ground had caused degradation of components in the power switches, which had resulted in unreliable operation of control rod No. 65. The NRC is evaluating the licensee's corrective actions for the forced reactor shutdown on September 17, 1999, the corrective actions for the reactor trip on February 11, 2000, and the relationship between the two events as part of the NRC's corrective action inspection. The inspection results will be documented in NRC Inspection Report 50-336/2000-03.

In addition to the specific actions for control rod Nos. 63 and 65, the licensee implemented a modification to increase the fuse rating for the control rod drive power leads and conducted extensive control rod testing. During the control rod testing, the licensee found that power switch contacts in other rods were degraded and unreliable. The licensee replaced degraded contacts, but the availability of replacement components was limited due to equipment obsolescence. Although the licensee made their best effort to assure proper functioning with available replacement parts, the reliability of the power switches remains in question. However, this unreliability is not an operability concern because it has no impact on the safety function of the control rod drive mechanisms, which is to unlatch the control rods so they drop freely into the core when the reactor trip breakers open and interrupt power to the drive mechanism coils. This function is independent of the power switches.

The inspector reviewed the licensee's corrective actions to address Condition Report M2-00-0374, which documented the unexpected RCS cooldown, and found that due to a misunderstanding in the scope of the event, the issue had not been addressed and the associated corrective action assignment had been closed. The inspector discussed this concern with the licensee, who then reopened the issue and determined that the unexpected cooldown of the reactor coolant system was caused by the valves for the second stage reheat steam supply to the moisture separator/reheaters remaining open because their controllers were in manual versus automatic. Due to on-line repairs to these steam supply valves, second stage reheat was placed in service with the plant on-line by opening the valves with their controllers in manual as specified in the associated operating procedure. However, the operating procedure was deficient in that it did not specify placing the controllers in automatic at the completion of the evolution. As a result, the valve remained open after the reactor trip and the operators were unnecessarily challenged by the cooldown.

c. Conclusions

On February 11, 2000, operators appropriately initiated a manual reactor trip when two control rods dropped completely into the core during control rod testing. The licensee's corrective actions to address the causes of the dropped rods (i.e., a ground in a power switch module and a separate ground in a drive mechanism coil) were acceptable. When further testing identified degradation of components in the control rod power switch modules, equipment obsolescence hampered the licensee's ability to effectively resolve the resultant reliability problems due to difficulties in obtaining replacement parts. About 25 minutes after the reactor trip, operators responded well to an unexpected cooldown and quickly restored pressurizer level. The NRC found that the licensee had closed the corrective action assignment addressing the cooldown without resolving the issue. Subsequently, the licensee determined that due to a deficient procedure, the controllers for steam supply valves for the moisture separator/reheaters were left in manual. As a result, the valves remained open after the reactor trip and operators were unnecessarily challenged by the cooldown.

O7 Quality Assurance in Operations

O7.1 Response to Generic Letter 98-02

a. Inspection Scope (TI 2515/142)

The inspectors reviewed Northeast Nuclear Energy Company's (NNECO's) activities for Millstone Units 2 and 3 related to NRC Generic Letter (GL) 98-02, "Loss of Reactor Coolant Inventory and Associated Loss of Emergency Mitigation Functions While in a Shutdown Condition". The inspection was conducted using Temporary Instruction 2515/142. The inspectors reviewed NNECO's engineering evaluations for GL 98-02, independently verified the evaluation, and interviewed the responsible engineering personnel.

b. Observations and Findings

Background: In 1994, the Wolf Creek nuclear station experienced a loss of reactor coolant system (RCS) inventory while the plant was in a hot shutdown condition. The event occurred while operators were changing the residual heat removal (RHR) system lineup while unrelated RHR valve maintenance was in progress. As a result, over 9000 gallons of RCS inventory were drained to the refueling water storage tank (RWST). In addition to reducing the RCS inventory, the event had the potential to incapacitate the emergency core cooling system (ECCS) pumps, which would have been required to supply core cooling and makeup, due to steam binding.

The NNECO evaluations in response to GL 98-02 determined that neither unit was susceptible to a transient similar to the Wolf Creek event. The evaluations were based on reviews of the piping and instrumentation diagrams, the system operating procedures and descriptions, and the Final Safety Analysis Reports (FSARs). For each unit, the inspectors independently identified what appeared to be a potentially susceptible flowpath. The inspectors discussed the specific flowpaths with licensee personnel and determined the licensee's justifications for them not being susceptible were adequate. The details are described below.

Unit 2: There are two headers from the RWST to the ECCS pumps, one header for each train. The inspectors noted a potentially susceptible flowpath from the RCS (via 2-SI-440 or 2-SI-441) to the suction of the low pressure safety injection pumps (similar to RHR pumps) to the RWST (via 2-SI-432 or 2-SI-444). When aligning the system for shutdown cooling operation, the valves from the RWST are closed and the valves from the RCS are opened. Although the valves are procedurally controlled, the valves are not interlocked to prevent all of them from being open at the same time. The inspectors determined, during discussions with the Unit 2 system engineers, that the flowpath was not susceptible to a Wolf Creek scenario due to check valves (2-CS-14A/B) which prevent the RCS from a drain down to the RWST. The check valves are tested satisfactorily every outage for back leakage. Based on the physical barrier (i.e., the check valves) and the surveillance test results, the inspectors agreed with the NNECO evaluation that Unit 2 was not susceptible to an event similar to the Wolf Creek event.

Unit 3: All of the ECCS pumps take a suction from a common header off the RWST. The inspectors noted a potentially susceptible flowpath for a Wolf Creek scenario from the RCS to the suction of the RHR pumps (via MV8701A/B/C or MV 8702A/B/C), reverse flow through a check valve (V3 or V9), through the pump suction isolation valve from the RWST (SILMV8812A or B), to the RWST and the common suction header for all of the ECCS pumps. The 8701/8702 valves are procedurally opened after the plant has cooled down from normal temperatures to hot shutdown conditions (i.e., less than 350°F). There is a permissive interlock which requires the 8812 valves to be closed before the 8701/8702 valves can be opened; however, the interlock would not prevent the 8812 valves from being reopened after the 8701/8702 valves had been opened. The only physical barrier between the hot RCS and the RWST is the check valve. The inspectors reviewed the inservice test data for the two check valves and noted that the reverse flow test results were below the acceptance criteria of 0.1 gallon per minute. Based on the physical barrier (i.e., the check valves) and the surveillance test results, the inspectors agreed with the NNECO evaluation that Unit 3 was also not susceptible to an event similar to the Wolf Creek event.

In addition, the inspectors noted the Unit 2 and the Unit 3 FSARs state that the failure of a check valve to seat to prohibit flow in the reverse direction is not considered to be a credible event. This position was discussed with the responsible inspector from the Reactor Systems Branch in the NRC Office of Nuclear Reactor Regulation and found to be acceptable.

c. Conclusions

NNECO evaluated the Wolf Creek event, in response to NRC GL 98-02, and determined that neither unit was susceptible to a similar type of scenario. The inspectors considered the evaluations to be adequate.

U2 O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) URI 50-336,423/97-01-03; Inaccurate Personnel Qualification Statements

The inspector conducted an on-site review of unresolved item (URI) 50-336,423/97-01-03, which addresses deficiencies in the licensee's approach to implementing, documenting, and submitting NRC Form 398, Personnel Qualifications Statement records. In support of this review, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, Millstone Training Department procedures and instructions, a sample of Millstone self-assessments and audits, and a selection of written licensee responses to NRC confirmatory action letter (CAL) for training, dated April 2, 1997, were also inspected.

As part of the corrective actions for the NRC CAL and several associated NRC-identified deficiencies, the licensee implemented extensive reviews, program upgrades and peer evaluations of Millstone licensed operator training, training documentation, and training administration. Failing to adequately establish and document adequate licensed operator training and training records is a violation of 10 CFR 50.55, Operators' Licenses. Because, this URI represents a small specific part of a larger condition that was identified by the NRC CAL and corrected by the licensee, the technical, organizational and administrative aspects of this URI are considered to be dispositioned from an enforcement perspective. This issue was addressed in the licensee's corrective action program through Condition Reports M3-99-0986, 1013, 1010, 1011, and 1012. The licensee's corrective actions were adequate.

Additionally, the licensee, in a plea bargain in a U.S. District Court in September 1999, agreed to pay a $5 million fine for the training record violations that resulted in the utility submitting incorrect operator license qualification statements to the NRC. This action by the U.S. Department of Justice (DOJ) was taken after the training inadequacies had been investigated by the NRC and subsequently corrected by the licensee. Although the NRC is continuing to review training-related issues at Millstone, with respect to individual culpability, the programmatic aspects of this problem have been satisfactorily addressed by the licensee and by the noted DOJ enforcement action. Therefore, **URI 50-336,423/97-01-03** is **closed**.

O8.2 (Closed) LER 50-336/99-014-00; Failure to Enter Limiting Condition for Operation While Testing a Containment Isolation Valve

a. Inspection Scope (90712)

The inspector performed an on-site review of the actions taken by the licensee to address the issues identified in licensee event report (LER) 50-336/99-014-00. The reviews included inspection of the licensee's corrective actions and supporting references and discussions with licensee engineering personnel.

b. Observations and Findings

On October 12, 1999, the licensee identified that operators failed to enter Technical Specification (TS) Limiting Condition for Operation (LCO) 3.6.3.1.b, “Containment Isolation,” when a containment isolation valve, 2-SI-628, failed a stroke test surveillance. As a result, valve 2-SI-628 was closed but was not deactivated in the closed position as specified in the LCO. The LER states that the cause of this event was human error in that operators failed to recognize valve 2-SI-628 as a containment isolation valve. The corrective action listed in the LER was to brief operators on this event. The licensee documented the issue in Condition Report M2-99-2749. The inspector also noted that the licensee removed valve 2-SI-628 from the list of containment isolation valves when they discovered that other valves for the penetration are actually credited for containment isolation. Therefore, the safety significance of the event was minimal. The licensee’s corrective actions were found to be adequate.

c. Conclusions

The licensee identified in October 1999 that operators failed to enter a TS LCO when a containment isolation valve failed a stroke test. The licensee’s corrective actions were found acceptable. This failure constitutes a violation of minor significance and is not subject to formal enforcement action. LER 50-336/99-014-00 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 M2-98-08905 — “B” Containment Air Recirculation Fan Electrical Breaker Preventive Maintenance
- AWO M2-00-01414 — “B” Emergency Diesel Generator Service Water Discharge Piping Leak Inspection
- AWO M2-00-00903 — “B” Main Steam Isolation Valve Low Air Pressure Alarm Switch Temporary Modification

•	AWO M2-99-00012	"A" Main Exhaust Fan Assembly Discharge Damper - Design Change Notice DM2-00-0089-99
•	Procedure SP 2402-PD	Safety System Functional Test - Channel "D"

The inspector also reviewed post maintenance testing associated with the following AWOs:

•	AWO M2-00-01970	Repair Leaking Steam Trap in Turbine Driven Auxiliary Feedwater Pump Room
•	AWO M2-99-14181	Replace Reactor Coolant Loop No. 1 Hot Leg Channel "D" Resistance Temperature Detector

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 incomplete tagging of boundary valves for the diesel generator service water discharge piping inspection. The piping inspection involved removing a service water elbow outside in the yard area and lowering a robotic camera into the open pipe. The inspector identified that valve 2-SW-297, which is used to provide alternate diesel cooling with fire protection water and was locked-closed, was not tagged. The inspector discussed this concern with the operations work control senior reactor operator. Valve 2-SW-297 was tagged prior to initiating work to inspect the piping. The safety significance of this incomplete tagging was low in this instance because the fire protection valve was locked closed. In addition, had fire protection water been aligned to the service water header, there was no risk of internal flooding and only minor potential for personnel injury.

c. Conclusions

Overall, the conduct of the maintenance and surveillance activities was found acceptable. However, the NRC identified that the tagging boundary for a service water piping inspection was incomplete. In this instance, the incomplete tagging was of low safety significance. Therefore, this failure constitutes a violation of minor significance and is not subject to formal enforcement action.

U2 M8 Miscellaneous Maintenance Issues

M8.1 (Closed) URI 50-336/97-202-02; Main Steam Check Valve Testing

a. Inspection Scope (92903)

This inspection involved a review of unresolved item (URI) 50-336/97-202-02, which questioned whether or not the inspection, maintenance, and testing associated with the main steam check valves were adequate and in accordance with regulatory requirements. The inspector conducted an on-site review of 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 and maintenance documentation.

b. Observations and Findings

The main steam check valves are credited in the Unit 2 FSAR accident analysis for preventing the blowdown of the intact steam generator in the event of a main steam line break (MSLB) upstream of the main steam isolation valves (MSIVs). Inservice testing and inspection requirements indicate that during each shutdown that the check valves should travel smoothly and completely to the closed position as steam plant load is reduced from 100% to 0% steam flow or receive corrective maintenance. These requirements are met by licensee test procedure SP 21134, “Main Steam System Valves Operational Readiness Test," the Millstone corrective maintenance program, and procedure EN 21221, “Check Valve Examination and Testing." The inspector verified that for those instances when the licensee identified that proper maintenance or testing had not been performed, adequate corrective action was affected. No violations of NRC requirements were identified.

c. Conclusion

The implementation of main steam check valve inspection, maintenance, and testing was found to be adequate. No violations of NRC requirements were identified. URI 50-336/97-202-02 is **closed**.

M8.2 (Closed) EEI 50-336,423/97-202-06; Maintenance and Technical Training

The inspector conducted an on-site review of apparent violation (EEI) 50-336,423/97-202-06, which addresses deficiencies in the licensee’s systems approach to training (SAT), as required by 10 CFR 50.120, Training and Qualification of Nuclear Power Plant Personnel. In support of this review, Unit 2 and 3 technical specifications (TS), associated corrective actions documented in the licensee’s corrective action process, Millstone training corrective action plan (CAP), Millstone Training Department procedures and instructions, a sample of Millstone self assessments, and a selection of written licensee responses and corrective actions to NRC confirmatory action letter (CAL) for training, dated April 2, 1997, were also inspected.

10 CFR 50.120, Training and Qualification of Nuclear Power Plant Personnel, requires in part, that learning objectives describe desired performance after training, evaluation of trainee mastery be conducted during training and training be assessed based on the performance of trained personnel in the job setting. EEI 50-336,423/97-202-06 identified numerous examples of failure to implement these requirements and/or ineffective corrective actions on the part of the licensee to eliminate known weaknesses in its application of SAT.

As part of their corrective actions for the NRC CAL and several associated NRC violations (including most recently NCV 50-336/99-10-02), the licensee implemented extensive reviews, program upgrades and peer evaluations of Millstone SAT implementation. In addition, Training Department procedures, organization and functional responsibilities were also addressed. Failing to adequately establish and implement a SAT is a violation of 10 CFR 50.120, Training and Qualification of Nuclear Power Plant Personnel. Because, this specific deficiency was part of a larger condition that was identified by the NRC CAL and corrected by the licensee, the technical, organizational and administrative aspects of this issue are considered to be dispositioned from an enforcement perspective. This issue was addressed in the licensee's corrective action program through Condition Reports M3-97-1979, 1980, and 1981. The licensee's corrective actions were adequate. Although the NRC is continuing to review training related issues at Millstone, this apparent violation (EEI) 50-336,423/97-202-06 is **closed**.

M8.3 (Closed) LER 50-336/98-08-00; Technical Specification Violations

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of licensee event report (LER) 50-336/98-08-00, Unit 2 technical specifications (TS) 4.3.2.1 and 4.3.3.4, associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR) and selected operating procedures.

b. Observations and Findings

On May 8, 1998, while Unit 2 was defueled, the licensee identified historical instances where TS required surveillances were not performed. The licensee's corrective actions included surveillance procedure updates and proposed TS changes.

The inspector determined that the instances were historical in nature and were subsequently performed prior to the restart of the unit. Several of the missed surveillances involved the proper overlap of individual surveillance tests and there was no pattern of surveillance failure for the concerned equipment (safety injection actuation system circuits, main steam isolation circuits and meteorological tower wind speed circuits). The failure to adequately implement surveillances as required by Unit 2 TS 4.3.2.1, Engineered Safety Feature Actuation System Instrumentation and 4.3.3.4, Meteorological Monitoring Instrumentation is a violation of NRC requirements. 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 Reports M2-98-1118 and 1437 into the licensee's corrective action process. The licensee's corrective actions were found acceptable.

c. Conclusions

The licensee identified in 1998 that historically, certain Unit 2 TS required surveillance tests had not been adequately performed. This is a violation of Unit 2 TS 4.3.2.1, Engineered Safety Feature Actuation System Instrumentation and 4.3.3.4, Meteorological Monitoring Instrumentation. The licensee's corrective actions were found acceptable. This violation is being treated as a **Non-Cited Violation (NCV 50-336/2000-01-01)**. LER 50-336/98-08-00 is **closed**.

M8.4 (Closed) LER 50-336/98-010-00; Analysis of Enclosure Building Stack Effects

a. <u>Inspection Scope (37550, 92700, 92903)</u>

The inspector conducted an on-site review of licensee event report (LER) 50-336/98-010-00, Unit 2 technical specification (TS) 3.6.5.2, associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report Sections 6.7.2 and 6.7.4 and selected operating procedures.

b. <u>Observations and Findings</u>

On May 8, 1998, while Unit 2 was defueled, the licensee identified that a historical deficiency existed in the surveillance used to verify the leak integrity of the Unit 2 enclosure building. The surveillance did not consider a combination of environmental considerations, including air temperature, wind speed and stack effect on enclosure building differential pressure. Postulated worst case conditions could have prevented the enclosure building from reaching its design basis post-accident, negative pressure.

The licensee's corrective actions included the performance of an engineering analysis and TS surveillance procedure updates. The failure to establish an adequate surveillance procedure for testing the enclosure building is a violation of Unit 2 Technical Specification 6.8.1.c. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the <u>NRC Enforcement Policy</u>, 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 M2-98-1275 into the licensee's corrective action process. The licensee's corrective actions were found acceptable.

c. <u>Conclusions</u>

In 1998, the licensee identified a historical condition involving the fact that a failure to establish a surveillance procedure did not verify that the enclosure building would maintain the negative pressure assumed in its design basis. During worst case conditions, this could have resulted in increased post accident leakage to the atmosphere from Unit 2 containment. The licensee's corrective actions were found acceptable. The failure to establish an adequate surveillance procedure for testing the enclosure building is a violation of TS 6.1.8.c. This violation is being treated as a **Non-Cited Violation (NCV 50-336/2000-01-02)**. LER 50-336/98-010-00 is **closed**.

M8.5 (Closed) LER 50-336/99-016-00; Technical Specification Surveillance Requirements of Seismic Instrumentation Were Not Historically Met

a. Inspection Scope (92700)

The inspector conducted an on-site review of licensee event report (LER) 50-336/99-016-00, the Millstone Unit 2 Technical Specifications, the associated Unit 2 surveillance procedure, and the corrective actions documented in the licensee's corrective action process.

b. Observations and Findings

On December 1, 1999, the licensee identified that the technical specification surveillance requirements for seismic instrumentation had not been historically met. At the time the issue was identified, the NRC had approved relocating the surveillance requirements for seismic instrumentation from the Millstone Unit 2 Technical Specifications to the Unit 2 Technical Requirements Manual, and the licensee had implemented the change. However, prior to the technical specification change, the surveillance requirement had specified a complete channel calibration of the instrument on a refueling interval, but the associated surveillance procedure specified calibration of only four of the twelve reeds in each of the three boxes that comprise the tri-axial response spectrum recorder. Because the technical specification definition of a channel calibration specifies calibration of the entire channel including the sensor, execution of the surveillance procedure as written failed to completely satisfy the technical specification requirement. The procedure steps that specified calibration of only four of the twelve reeds had been in place since October 1976 and were based on the original equipment manufacturer's recommendation.

The inspector found the licensee's corrective actions to be adequate. In January 2000, the licensee performed a complete calibration of the spectral response recorder to satisfy the calibration periodicity specified in the Unit 2 Technical Requirements Manual, and the results of the calibration were satisfactory. The inspector found that the historical failure to completely satisfy the technical specification surveillance requirements had low safety significance based on the following factors:

(1) Seismic data was available from Unit 2 accelerographs to determine necessary actions following a postulated earthquake. In addition, the full complement of Unit 3 seismic instrumentation was available.
(2) The assumed loss of function of the spectral response recorder did not affect the ability to ensure initial conditions of accident analyses are satisfied, nor did it affect the structures, systems, and components designed to prevent or mitigate an accident.

c. Conclusions

The inspector concluded that the licensee's corrective actions were acceptable and that the historical failure to completely satisfy the technical specification surveillance requirements was of low safety significance. Therefore, this failure constitutes a violation of minor significance and is not subject to formal enforcement action. LER 50-336/99-016-00 is **closed**.

U2.III Engineering

U2 E8 Miscellaneous Engineering Issues

E8.1 (Closed) LER 50-336/98-05-00, 01, & 02; High Energy Line Break

The inspector conducted an on-site review of licensee event report (LER) 50-336/98-05-00, 01 & 02, which addresses several aspects of a 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 technical evaluations and modification documentation.

As part of their corrective actions for numerous NRC findings concerning the design basis of Unit 2, the licensee implemented extensive reviews of the Unit 2 design basis. The licensee's corrective actions for the specific conditions identified in LER 50-336/98-05-00, 01, & 02 included procedure updates, drawing changes, mechanical modifications, verification of historical performance, vendor, qualification and test data, and revised post-HELB engineering calculations. The failure to adequately establish and implement design controls to ensure that safety-related system criteria include appropriate HELB considerations is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. Because, the conditions reported in revisions 01 and 02 of LER 50-336/98-05 were identified, reported and corrected by the licensee in response to NRC violation 50-336/98-219-11, the conditions are considered to be dispositioned from an enforcement perspective. HELB issues were entered into the licensee's corrective action program in numerous Condition Reports, including M2-98-0748 and 2497. The inspector determined that the licensee's corrective actions were adequate. LER 50-336/98-05-00, 01, & 02 is **closed**.

E8.2 (Closed) LER 50-336/98-011-00; Feedwater Valve Closure

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of licensee event report (LER) 50-336/98-011-00, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), selected maintenance procedures and supporting operating procedures.

b. Observations and Findings

On May 19, 1998, while Unit 2 was defueled, the licensee identified that a historical condition existed related to the closing of the feedwater isolation valves during maximum flow conditions. As a result of this condition, the feedwater isolation valves may have failed to fully close following a fast closure signal during a main steam line break (MSLB) design basis event. If the feedwater valves failed to close, a larger than assumed amount of water would enter a faulted steam generator, resulting in containment pressures that exceed those analyzed for in the FSAR.

The licensee's corrective actions included modifications to the seating surfaces in the valves, adjustments to the limit and torque switches on the valve motors, procedure updates, drawing updates, and the performance of an engineering analysis. The failure to adequately establish and implement design controls to ensure that the feedwater isolation valve 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 M2-98-1404 into the licensee's corrective action process.

c. Conclusions

In 1998, the licensee identified a historical condition involving the potential failure of the main feedwater isolation valves to fully close following a main steam line break which would have resulted in the Unit 2 containment exceeding its design pressure. This is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. The licensee's corrective actions were found acceptable. This violation is being treated as a **Non-Cited Violation (NCV 50-336/2000-01-03)**. LER 50-336/98-011-00 is **closed**.

E8.3 (Closed) LER 50-336/98-013-00; Potential to Overpressurize the Shutdown Cooling System

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of licensee event report (LER) 50-336/98-013-00, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), and supporting operating procedures.

b. Observations and Findings

On May 26, 1998, the licensee identified that historical assumptions concerning operator response to an inadvertent start of a high pressure safety injection (HPSI) pump could result in the shutdown cooling (SDC) system exceeding its design basis pressure. The postulated pressure transient would have lasted for approximately four minutes. Calculations showed that the postulated transient would not have exceeded the SDC system's hydrostatic test pressure.

The licensee’s corrective actions included procedure updates, drawing updates, and additional design basis verification. The failure to adequately establish and implement design controls to ensure that SDC system 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’ corrective action program. This issue was entered as Condition Report M2-98-1499 into the licensee’s corrective action process. The licensee's corrective actions were adequate. LER 50-336/98-013-00 is closed.

c. Conclusions

In 1998, the licensee identified a historical shutdown cooling system configuration in which an inadvertent start of a HPSI pump could have resulted in the SDC system exceeding the pressure assumed in its design basis for approximately four minutes. This is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. The licensee’s corrective actions were found acceptable. This violation is being treated as a **Non-Cited Violation (NCV 50-336/2000-01-05)**. LER 50-336/98-013-00 is **closed**.

E8.4 (Closed) LER 50-336/98-014-00; Control Room Ventilation Boundary Operations

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of licensee event report (LER) 50-336/98-014-00, 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. Observations and Findings

On September June 29, 1998, while Unit 2 was defueled, the licensee identified that historically, certain plant procedures allowed control room doors and control room ventilation access doors and covers to be blocked open for maintenance and other related activities. Instances were also identified where this practice occurred. Blocked open ingress paths into the control room ventilation spaces were not assumed to exist in the Millstone Unit 2 FSAR and represented conditions outside of the design basis of the unit.

The licensee’s corrective actions included procedure updates, drawing updates and additional design basis verification. Failing to adequately establish and implement design controls to ensure that certain design basis criteria of the control room ventilation system 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 M2-98-1881 into the licensee’s corrective action process. The licensee’s corrective actions were adequate. LER 50-336/98-014-00 is **closed.**

c. Conclusions

In 1998, the licensee identified that historically, Unit 2 procedures and practices allowed the control room ventilation system doors and covers to be blocked open during power operations. This placed the control room ventilation system in a condition outside of its design basis. This is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. The licensee’s corrective actions were found acceptable. This violation is being treated as a **Non-Cited Violation (NCV 50-336/2000-01-04)**. LER 50-336/98-014-00 is **closed**.

E8.5 (Closed) LER 50-336/98-017-00 & 01; Fire Protection Program Deficiencies

LER 50-336/98-017-00 & 01 addressed several Millstone fire protection program deficiencies. The deficiencies included incomplete documentation of fire penetration seals, inadequate protection for certain fire dampers, general work control and design verification weaknesses, procedure weaknesses, and inadequate protection of structural supports.

The inspector conducted an on-site review of licensee event report (LER) 50-336/98-017-00 & 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, Northeast Utilities Fire Protection Program Manual and a selection of fire protection related audit findings, plant technical evaluations and modification documentation. Because, the conditions reported in the LER were identified, reported, and corrected by the licensee and were addressed, in part, as NRC violations 50-336/98-05-10 and 50-336/99-12-04, the deficiencies are considered to be dispositioned from an enforcement perspective. These fire protection deficiencies were entered into the licensee’s corrective action program in numerous Condition Reports, including M2-98-2317, 3030, 3432, and 2326. The inspector determined that the licensee's corrective actions were adequate. LER 50-336/98-017-00 & 01 is **closed**.

E8.6 (Closed) LER 50-336/99-015-00; Unanticipated Reactor Protection System Trip Signal on Low Steam Generator Level

NRC Inspection Report (IR) 50-336/99-09 discusses an inadvertent actuation of the reactor protection system (RPS) that occurred on September 19, 1999, due to low steam generator water level, while the unit was shut down. NRC IR 50-336/99-09 stated that the licensee incorrectly retracted their initial notification of this unplanned RPS actuation. The NRC concluded that this retraction constituted a failure to report a condition as required by 10 CFR 50.72(b)(2)(ii) and Non-Cited Violation 50-336/99-09-03 was issued. The licensee subsequently issued licensee event report (LER) 50-336/99-015-00 that addressed the inadvertent RPS actuation. In addition, Non-Cited Violation 50-336/99-09-02 was issued that addressed the inadequate plant cooldown procedure that caused the inadvertent RPS actuation. The licensee’s corrective actions of changing the cooldown procedure and reviewing other procedures for similar problems were found acceptable. Based on the inspection of this issue in NRC IR 50-336/99-09, LER 50-336/99-015-00 is **closed**.

Report Details

Summary of Unit 3 Status

Unit 3 began the inspection period on January 4, 2000, operating at 100 percent power. On January 22 operators reduced reactor power to approximately 93 percent to facilitate maintenance on the "B" moisture separator drain tank normal level control valve. Following maintenance completion later that day, operators restored power to 100 percent where it remained through the end of the inspection period on February 14.

Several organizational changes became effective during this report period. Mr. Ray Necci was named Vice President - Nuclear Technical Services, replacing Mr. Dave Amerine, Vice President - Engineering Services. Mr. Steven Scace was named to the new position of Director - Nuclear Oversight and Regulatory Affairs, assuming all the organizational roles and responsibilities formerly performed by Mr. Necci. Mr. Mike Ahearn was named the acting Director - Nuclear Oversight, assuming all responsibilities formerly held by Mr. Scace.

U3.I Operations

U3 O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations in accordance with NRC inspection procedure 71707. Shift turnover activities were witnessed, control room logs were reviewed, and daily plant status meetings were observed to evaluate the effectiveness of operations oversight by the shift managers and station management personnel. During the inspection-tours of the control room, the licensed operators were interviewed to assess their knowledge of plant and system status, as well as to understand the reasons for certain main board equipment tags and any lit annunciators. During this inspection period, very few unplanned limiting conditions for operation (LCO) were entered and correspondingly, the unit was operated with few unexpected alarm conditions. One lit annunciator questioned in detail by the inspector is discussed further in Section E2.1 of this report.

U3 O2 Operational Status of Facilities and Equipment

O2.1 Field Inspection-Tours - Plant Equipment Status

a. Inspection Scope (71707, 62707)

The inspectors conducted walkdowns of selected portions of safety-related systems during routine inspection-tours of the plant. Component conditions were observed and equipment status, including valve and electrical breaker positions, was evaluated with respect to both technical specification (TS) requirements and Final Safety Analysis Report (FSAR) descriptions.

b. Observations and Findings

The inspector checked the status of temporary equipment restraints in several safety-related areas in Unit 3. The control of ladders, gas cylinders, tool boxes, and scaffolding, in particular, was evaluated with respect to the procedural provisions of OA-8, “Ownership, Maintenance, and Housekeeping of Site Buildings, Facilities, and Equipment.” The inspector noted in some previous areas (e.g., main steam and feedwater building) where the restraints of some 3-ton trolley/crane components had been questioned, that the current equipment conditions were in full compliance with OA-8 requirements.

The inspector also examined some motor operated valves for position, indication and actuating power supply status. Valve position, where required, was evaluated with regard to the TS and operational control provisions; and in the case of certain valves (e.g., the safety injection accumulator isolation valves), the FSAR statements regarding interlock controls during power operation were verified as correct with the power supply breakers open. The throttled condition of some valves in the primary plant component cooling (CCP) system and the locked valve conditions in the safety injection pump cooling (CCI) system were verified as correct with regard to piping and instrumentation drawings and validation of an open cooling flow path to safety-related equipment. Various load centers and motor control centers were also checked for breaker status consistent with the powered equipment conditions noted in the control room. In one case, while a “red tagged” open breaker on 480 volt bus 32-1W was found consistent with a lit annunciator on the main control board, some additional inspection questions were raised with respect to this equipment status, as is further discussed in Section E2.1 of this report.

The inspector conducted a review of the operations handing of an identified electrical ground on a control valve (3FWA*HV32C) in the discharge piping from the turbine driven auxiliary feedwater (TDAFW) pump. Although the ground was not found to be associated with this TDAFW valve until sometime after the control room alarm was received, the operators entered the appropriate technical specification action statement for an inoperable TDAFW condition at the time the ground was identified, thus assuring that the proper allowed outage time controls were maintained in accordance with the TS for this system. Subsequently, the affected Target-Rock valve circuitry was evaluated by instrumentation and control (I&C) technicians, corrective maintenance was performed with the replacement of a faulty instrument card, and both the valve and the TDAFW system were restored to an operable status in an expeditious manner and with the proper controls in evidence.

The inspector also observed the controls implemented by operations for the delivery and off-loading of CO_2 into the designated Unit 3 fire suppression storage tank. A plant equipment operator (PEO) performed and directed these activities in accordance with operations procedure OP 3341 requirements. The delivery truck driver was escorted onsite by a security guard and turned over to the PEO for escort control of a visitor. During a subsequent plant inspection-tour during back-shift hours, the inspector noted a flashing strobe light at the CO_2 storage tank. This condition was discussed with the operations supervisor and the inspector subsequently learned that based upon the setpoint for CO_2 level and pressure, the noted flashing was a normal condition after a tank fill. Operator actions and responses to inspector questions with respect to the observed evolution and conditions were both timely and appropriate. Additionally, during this inspection period, the licensee completed its review of operations protocol and key controls to provide assurance that operations personnel had been provided the requisite training and the correct keys to operate Train "A" safe shutdown equipment in the event that a control room evacuation was necessary. During a previous inspection, the inspector had questioned the scope, guidance, and "local" key-lock controls for certain safety-related Train "A" equipment that was not covered in any abnormal or emergency response procedures. In assessing the scope of the affected Train "A" equipment, the licensee confirmed that several plant equipment operators were capable of responding to the affected areas and operating the subject Train "A" equipment, when required, without the need for additional administrative controls. The inspector conducted a field walkdown of the areas housing the affected Train "A" components and identified no further questions or concerns in this regard.

The inspector also reviewed Operability Determination (OD) MP3-004-00, dated January 22, 2000, evaluating the drop in the ultimate heat sink (i.e., service water system) temperature below its minimum design limit of 33°F on January 21. The inspector noted that the OD had received plant operations review committee (PORC) approval and that the OD discussion provided a reasonable basis for continued operation of the unit with the service water system temperature as low as 29°F. A Licensee Event Report (LER 2000-01) was subsequently submitted by the licensee to describe this condition as one outside the design basis of the plant. LER 2000-01, submitted on February 17, 2000, shortly after the end of this report period, remains open for further inspector review.

c. Conclusions

Operations personnel response to plant equipment problems and cold weather conditions was both timely and appropriate. A licensee event report was issued, and remains open, to document a condition outside the design basis of the plant, but the noted event was adequately evaluated with respect to affected component operability. Plant inspection-tours revealed housekeeping, equipment status, and tagging/lineup controls consistent with procedural provisions and system configurations being tracked by the operators on shift in the control room.

O7 Quality Assurance in Operations

O7.1 Response to Generic Letter 98-02

The inspection discussion for this issue, common to Units 2 and 3, is in Section U2.O7.1 of this report.

U3 O8 Miscellaneous Operations Issues (92700, 92901)

O8.1 (Closed) URI 50-423/97-01-03; Inaccurate Personnel Qualification Statements

The closure discussion for this item, common to Units 2 and 3, is in Section U2.O8.1 of this report.

O8.2 (Closed) IFI 50-423/97-82-03; Organizational Independence of Human Factor Engineering Personnel

Inspector Followup Item (IFI) 50-423/97-82-03 was written to review the organizational independence of human factor engineering personnel, while they performed technical specification (TS) related audit activities. The inspector conducted an on-site review of the Unit 3 TS, Unit 3 License Amendment 173, associated corrective actions documented in the licensee's corrective action process, the Unit 3 Final Safety Analysis Report (FSAR), Northeast Utilities Quality Assurance Program Manual and a selection of Independent Safety Evaluation Group (ISEG) audit findings.

The assignment of Human Factor Engineering (HFE) personnel as support personnel to ISEG and other audit functions was determined, by the inspector, to be acceptable and no instances were identified where the independence or quality of the auditing activity was affected by the participation of HFE personnel. The licensee's administrative corrective actions were determined to be adequate and no violation of NRC requirements was identified. **IFI 50-423/97-82-03** is **closed**.

O8.3 (Closed) IFI 50-423/97-82-04; Corrective Action Program Lacked Controls

Inspector Followup Item (IFI) 97-82-04 was opened following the NRC's 40500 Team Inspection conducted in February 1998. As detailed in NRC Inspection Report 50-423/97-82, the team identified that the licensee had inadequate controls within the corrective action program, in that a number of condition reports (CR) had been combined or closed out to existing CRs in a manner that did not preserve the original issue or CR significance level.

The inspector reviewed the licensee's actions in response to the issues identified in IFI 97-82-04. The inspector noted that the licensee had implemented a revision to RP-4, "Corrective Action Program," which included guidance regarding the process to be followed when evaluating whether one CR may be combined with or closed to another CR. The inspector's review determined that these licensee actions adequately address the underlying issue represented by this item. Therefore, **IFI 50-423/97-82-04** is **closed**.

O8.4 (Closed) IFI 50-423/97-83-05; Qualification of Fire Brigade Supervisor and Members

Inspector Followup Item (IFI) 50-423/97-83-05 was written to review the qualification of fire brigade members and the brigade supervisor, and to ensure that Final Safety Analysis Report (FSAR) Change 26 was accepted by the NRC. The inspector conducted an on-site review of the Unit 3 TS, Unit 3 FSAR, associated corrective actions documented in the licensee's corrective action process (including CR M3-98-2131), Northeast Utilities Fire Protection Program Manual and a selection of fire protection related audit findings.

FSAR Change Request 26, effective June 1997, reconstituted the staffing of the fire brigade and established the training requirements for brigade members. The licensee established special operations training for team members to provide training in or knowledge of plant safety related systems, so that the brigade members understood the effects of fire and fire suppressants on the safe shutdown capability of the units. In addition, each brigade has assigned to it an advisor who is knowledgeable in safety related system operations, as demonstrated by the possession of an operator's license or equivalent certification. Changes to the fire brigade staffing and training were determined to be consistent with NRC Branch Technical Position CMEB 9.5-1. The licensee's administrative corrective actions were determined to be adequate and no violation of NRC requirements was identified. **IFI 50-423/97-83-05** is **closed**.

O8.5 (Closed) LER 50-423/99-02-00; Inadvertent Carbon Dioxide Fire Suppression System Actuation in the Cable Spreading Room

a. Inspection Scope (92700, 92901)

The inspector conducted an on-site review of licensee event report (LER) 50-423/99-02-00, Unit 3 technical specifications (TS), and associated corrective actions documented in the licensee's corrective action process.

b. Observations and Findings

On January 15, 1999, an inadvertent discharge of the carbon dioxide (CO_2) fire suppression system occurred in the cable spreading room. An NRC review of this event was documented in NRC Inspection Report 50-423/99-02. The licensee's post-trip review identified two items which were reported in the subject LER. First, on-shift operations personnel had not maintained proficiency in the use of self contained breathing apparatus (SCBA). This fact was voluntarily reported in the LER. SCBA were used in the control room when higher than normal CO_2 levels were identified there. Second, TS 3.0.3 was not entered when the control building purge system was utilized to clear the CO_2 from the control building. Use of this system caused both trains of the control room emergency ventilation system and the control room emergency pressurization system to be inoperable, requiring entry into TS 3.0.3.

The licensee determined that the requirement for all operators to be SCBA qualified was thought to be eliminated when the site fire brigade organization was formed in 1997, as it was thought that responding to a fire was the only reason for the requirement. As a result, the licensee chose to only qualify operators in respirators to meet emergency response requirements. Those operators with fire brigade duties remained SCBA qualified. Within a month of the CO_2 discharge, the licensee ensured that all shift operators were SCBA qualified. The inspector also verified that all shift operators were still SCBA qualified at the end of this inspection period and that this qualification is again being tracked to ensure lapses do not occur in the future. The NRC previously issued

NCV 50-423/99-02-08 for the failure to maintain design control when the licensee failed to adequately consider and evaluate carbon dioxide in the toxic chemical analysis for control room habitability.

The licensee determined that operators did not enter TS 3.0.3 due to confusing statements in the TS bases. Misapplication of licensing and design bases information led to inappropriate changes to the TS Bases. The inspector verified the completion of revisions to operating procedures and TS Bases to clarify operability of the control room emergency ventilation and the control room emergency pressurization systems. The NRC previously issued NCV 50-423/99-02-06 for the failure to enter TS 3.0.3.

Because the conditions were reported and corrected by the licensee and were addressed by previous NRC violations, this LER is considered to be dispositioned from an enforcement perspective. No further violation of NRC requirements was identified. These issues were addressed in the licensee's corrective action system as CRs M3-99-0130 and 0271. The licensee's corrective actions were adequate. Therefore, LER 50-423/99-02-00 is closed.

c. Conclusions

In January 1999, following the inadvertent discharge of carbon dioxide into the cable spreading room, the licensee identified that on-shift operations personnel had not maintained proficiency in the use of self contained breathing apparatus (SCBA) and operators failed to enter TS 3.0.3 as required. Because the conditions were reported and corrected by the licensee and were addressed by previous NRC violations, this LER is considered to be dispositioned from an enforcement perspective. The licensee's corrective actions were found acceptable. **LER 50-423/99-02-00** is **closed**.

O8.6 (Closed) IFI 50-423/99-02-05; Containment Radiation Monitor Design Basis Function

Inspector Followup Item (IFI) 99-02-05 was opened due to NRC questions regarding the design basis capability of the containment radiation monitor, 3CMS*RE22, as detailed in NRC Inspection Report (IR) 50-423/99-02. In a related matter, as is documented in IR 50-423/99-09, an inspector reviewed and closed licensee event report 50-423/98-09, which addressed the licensee's failure to adequately implement design controls for 3CMS*RE22.

In response to the identified questions, the licensee initiated appropriate licensing and design basis changes regarding the capabilities of the containment radiation monitor. The licensee determined that while 3CMS*RE22 has the appropriate sensitivity to provide reactor coolant system (RCS) leak indications to control room operators, various factors, such as RCS activity levels, prevent the reliable use of the monitor to quantify RCS leaks consistent with Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems." However, the inspector determined that the licensee appropriately utilizes various other leak detection systems to comply with licensing and procedural requirements. Based upon these capabilities, as well as licensee implementation of licensing and design basis changes, the inspector determined that operations personnel have been provided the ability to comply with regulatory requirements, despite the identified inconsistency and NRC questions regarding the generic capabilities of the containment radiation monitors. Therefore, the inspector concluded that no further action is warranted and **IFI 50-423/99-02-05** is considered **closed**.

U3.II Maintenance

U3 M1 Conduct of Maintenance

M1.1 Surveillance Observations

a. Inspection Scope (61726)

The inspector observed portions of the following selected surveillances, discussed the conduct of work and controls with responsible personnel, and/or reviewed selected test results.

- SP 3623.2-1 Cycle Test of HP Turbine Stop Valve and LP Turbine Combined Intermediate Stop and Intercept Valves (Weekly)
- SP 3623.2-2 Cycle Test of HP Turbine Stop Valve and LP Turbine Combined Intermediate Stop and Intercept Valves (Monthly)
- SP 3446B11 Train A Solid State Protection System (SSPS) Operational Test

b. Observations and Findings

NRC Inspection Report 50-423/99-14, Section U3.M1.1, discussed the failure of the number five combined intermediate stop and intercept valve to fully stroke on December 22, 1999. This period the inspector reviewed the weekly and monthly surveillance test results for this valve since the failure and the closure documentation for the related Condition Report (CR), M3-99-4151. Instrumentation and Controls (I & C) personnel instrumented the valve during the four surveillance tests subsequent to the failure with no further problems identified. The inspector verified that the remaining tests this period also showed no failure. The licensee concluded that the previously observed failure was a one time occurrence and the CR was closed. The inspector determined the licensee's actions to be reasonable as justified by the continued successful performance of the valve in several subsequent tests.

In reviewing portions of the Train A SSPS operational test, the inspector verified the sequence of operator actions and control manipulations were consistent with the procedural provisions of SP 3446B11. The proper limiting conditions for operation were entered in accordance with TS 3.3.1 requirements. The inspector questioned one TS Table 3.3-1 entry (ACTION 13) when the "A" reactor trip bypass breaker was closed. Since the bypass breaker provides the same diverse trip features (undervoltage and shunt trip capabilities) available with the reactor trip breaker, it appeared that the entry into ACTION 13 was unnecessary. This was discussed with the unit supervisor, who agreed that this particular action statement was not applicable to the noted testing configuration. However, since several other more conservative TS action statements were controlling this evolution and the allowed outage times, the questioned TS entry had no regulatory impact.

Subsequently, the inspector reviewed the SP 3446B11 test record, noting satisfactory as-found and as-left conditions for all instrument channels relative to the procedural acceptance criteria. The inspector discussed a minor I&C Form 3446B11-1 inconsistency with a department manager in that the procedural steps for recording the as-left data were not referenced in all cases. This discrepancy had no impact upon the test results. The I&C manager noted the inspector's comment for discussion with the unit procedures group for future form enhancement.

c. Conclusions

Appropriate corrective actions were taken this inspection period following the previous failure of a Unit 3 combined intermediate stop and intercept valve to close during surveillance testing.

Acceptable performance of a Unit 3 solid state protection system operation test was verified, with some minor discrepancies noted by the inspector. These items did not adversely impact the good controls established by the operators during conduct of the testing, nor the successful completion of the testing in accordance with the procedurally prescribed test acceptance criteria.

U3 M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Station Blackout Diesel Generator Degraded Condition Analysis

a. Inspection Scope (62707, 92700)

The inspector reviewed a reportability determination regarding a degraded battery condition, identified during preventive maintenance activities, that could have prevented the successful start and run of the Unit 3 station blackout (SBO) diesel generator.

b. Observations and Findings

Based upon a low voltage condition on the battery that provides backup power to SBO diesel generator computer uninterruptible power supply (UPS), the licensee replaced the subject SBO UPS battery. These testing and maintenance activities occurred near the end of the last inspection report period. The SBO diesel generator requires its computer system to function for the diesel generator to start and supply power to a safety-related bus. Therefore, the measured voltage drop was viewed as a condition that would have prevented the SBO diesel generator from providing the alternate "a-c" power function within one hour after an SBO event, as described in the 8-hour coping period analysis for Unit 3. While this condition was appropriately identified during preventive maintenance and a subsequent SBO diesel generator start and run test demonstrated the equipment functionality, the inspector questioned whether the discovery that the

SBO diesel generator would not have started and run as required was a reportable event in accordance with 10 CFR 50.73.

The licensee documented its Reportability Determination, supporting the review of the battery conditions identified in condition report (CR) M3-00-0031, on January 19, 2000. The licensee concluded that the identified conditions were not reportable pursuant to 10 CFR 50.73. As background reference material to this Reportability Determination, the licensee also provided excerpts from the Unit 3 Safety Evaluation Report (NUREG-1031) dated July 1984, from NUREG-1109, “Regulatory/Backfit Analysis for the Resolution of Unresolved Safety Issue A-44, Station Blackout”, and from a 1999 NRC inspection report at another facility in which it is recognized by the NRC that the SBO diesel generator does not provide a safety-related function or support such a function at nuclear plants.

The inspector reviewed all of these documents and concluded that the licensee had provided a supportable basis for the determination that potential unavailability of the SBO diesel generator was not reportable. While the identified deficiencies were evaluated to represent neither a condition outside the design basis of the plant, nor one that is considered to be a loss of a safety function, the inspector noted that the licensee did take immediate corrective measures to restore the SBO capability and documented the problems in a condition report for further corrective action review. During this inspection period, the inspector also interviewed some operators on shift regarding what impact certain supporting equipment unavailability would have on the SBO diesel generator functionality. The inspector found the operator responses to be consistent with the SBO mitigation capabilities described in regulatory documents.

c. Conclusions

The licensee implemented timely and effective corrective measures to restore system functionality in response to equipment problems, discovered during preventive maintenance activities, that could have prevented the start and continued operation of the Unit 3 SBO diesel generator during a hypothesized SBO event. The licensee also provided a sound, documented basis as to why the identified degraded conditions did not constitute a reportable event pursuant to regulatory requirements and related guidance.

U3 M8 Miscellaneous Maintenance Issues

M8.1 (Closed) IFI 50-423/97-82-09; Quality Lacking in the Setpoint Control Program

a. Inspection Scope (37550, 92700, 92903)

Inspector Followup Item (IFI) 50-423/97-82-09, was written to review program controls that the licensee established over safety related and technical specifications (TS) required instrument and alarm setpoints, including verification that the setpoints were supported by the unit’s design basis. The inspector conducted an on-site review of the licensee’s setpoint control process, Unit 3 TS (including TS 6.8.4.c), associated corrective actions documented in the licensee’s corrective action process (including CR-

M3-98-2149), the Unit 3 Final Safety Analysis Report (FSAR), the Unit 3 master setpoint list, supporting codes and standards, and a selection of instrument calibration, setpoint, and testing documentation. Numerous NRC inspection reports (including 50-423/97-201, 206, 209, 210, and 50-336/97-211), and vendor design basis verification documents were also reviewed.

b. Observations and Findings

A sample of eleven safety-related setpoints was compared against design basis drawings and calculations. The inspector concluded that the setpoints selected were supported by the unit's design and that setpoint validation data, design basis information and supporting documentation was retrievable by the licensee. In addition, reviews of Unit 3 chemistry instrument setpoints for several safety-related and balance of plant systems indicated that these setpoints adequately established and implemented TS 3.1, Boration Control, TS 3.4, Reactor Coolant System Chemistry, and portions of the Unit 3 corrosion control process. It should be noted that the setpoint information continues to be stored in multiple storage locations on and off site. During this inspection, the licensee identified and corrected specific deficiencies in the establishment and control of certain Instrument setpoint data (CR-M3-00-0074). The inspector determined that the licensee's interim administrative corrective actions were adequate. There was no current indication that the deficiencies identified by the licensee resulted in exceeding any design basis assumption, safety-related setpoint or TS required setpoint. No violation of NRC requirements was identified. IFI 50-423/97-82-09 is closed.

c. Conclusions

The licensee's instrument setpoint control process was reviewed and determined to be adequately implemented and supported by the current design basis process. The licensee's interim administrative corrective actions were adequate to correct self-identified deficiencies and no violation of NRC requirements was identified. **IFI 50-423/98-82-09** is **closed**.

M8.2 (Closed) EEI 50-423/97-202-06; Ineffective Maintenance and Technical Training Evaluation

The closure discussion for this item, common to Units 2 and 3, is in Section U2.M8.2 of this report

M8.3 (Closed) IFI 50-423/98-207-14; Corrosion Control for Closed Cooling Water Systems

Inspector Followup Item (IFI) 50-423/98-207-14 was written to review the practices implemented by the licensee to control corrosion in the component cooling water (CCP), reactor plant chilled cooling water (RPCCW), safety injection pump cooling water (CCI) and charging pump cooling water (CCE) systems. The inspector conducted an on-site review of the Unit 3 TS, Unit 3 Final Safety Analysis Report (FSAR), Unit 3 chemistry program, a selection of vendor and industry materials associated with chemistry control, associated corrective actions documented in the licensee's corrective action process (including CR M3-97-4346, 97-3501 and 98-3252) and a selection of corrosion related technical evaluations. In addition, corrosion related chemistry, chemistry control, and performance data were reviewed. The licensee's administrative, interim and long term actions were determined to be adequate and no violation of NRC requirements was identified. **IFI 50-423/98-207-14** is **closed**.

M8.4 (Closed) LER 50-423/96-21-02; Components Not Included in the Inservice Test Program

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of licensee event report (LER) 50-423/96-21-02, Unit 3 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 3 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of inservice testing documentation.

b. Observations and Findings

On June 6, 1998, while Unit 3 was in Mode 5, the licensee identified that certain inservice testing (IST) requirements of the American Society of Mechanical Engineers (ASME) code were not fully implemented. The code testing is mandated by Unit 3 TS 4.0.5, Inservice Testing.

The licensee's corrective actions included procedure updates, drawing changes, verification of IST components and the implementation of an amended testing program. Failing to establish and implement adequate testing to ensure that the requirements of ASME Section IX were met is a violation of Unit 3 TS 4.0.5, Inservice Testing. This failure was addressed by LERs 423/96-21-00, 21-01, 23 and 24, which were adequately resolved and closed, with the reported IST program deficiencies documented as a violation of regulatory requirements and dispositioned from an enforcement perspective in inspection report 50-423/97-202. Because the conditions were reported and corrected by the licensee, are historical in nature, constitute a low level of risk-informed significance and were addressed by previous NRC enforcement action, the IST program problems associated with this supplement 2 to LER 96-21 are considered to have been also acceptably dispositioned. As a result, no additional violation of NRC requirements was identified. This issue was addressed in the licensee's corrective action system as Condition Report (CR) M3-96-0285. The licensee's corrective actions were adequate.

c. Conclusions

In 1998, the licensee identified that TS required, ASME code inservice tests had historically not been performed on certain Unit 3 components. This is a violation of Unit 3 TS 4.0.5, Inservice Testing. Because the conditions were reported and corrected by the licensee, are historical in nature, and were addressed by previous NRC violations, this LER is considered to be dispositioned from an enforcement perspective. The licensee's corrective actions were found acceptable. **LER 50-423/96-21-02** is **closed**.

U3.III Engineering

U3 E2 Engineering Support of Facilities and Equipment

E2.1 Review of Shutdown Instrument Air Compressor Design Capabilities

a. Inspection Scope (37551)

During a plant inspection-tour, the inspector noted the electrical supply breaker for a shutdown instrument air compressor (3IAS*C2B) danger (red) tagged open to support repair activities on a reactor plant component cooling (CCP) system valve. In evaluating the operational controls implemented for this work, the inspector examined the existing instrument air (IAS) system capabilities and the design modifications initiated, changed, and planned for the shutdown portion of the IAS system.

b. Observations and Findings

The inspector noted that a main control board annunciator was lit in the control room, consistent with unavailability of the power supply for 3IAS-C2B compressor. The inspector verified that the compressor itself was nonsafety-related, but that its electrical supply breaker was considered a safety component because it received power for a Class 1E power supply. Discussions with control room operators confirmed that both the C2A and C2B compressor controls had been placed in “pull-to-lock”, consistent with the IAS operating procedure, OP 3332A (Revision 13). However, further discussions with operations personnel and the IAS system engineer revealed that because of design problems originating during Unit 3 construction and testing, there was no intent to ever use either of the shutdown air compressors during any plant conditions again.

The inspector reviewed a design change record (DCR M3-97005) which provided acknowledgment that the shutdown air compressors cannot be used as originally intended (i.e., for operator use during a loss-of-power [LOP] event) because the non-safety portion of the CCP header that supplies cooling to these air compressors is also isolated during a LOP. This isolation of the non-safety CCP header was deemed necessary because of potential run-out conditions of the CCP pumps, which was identified as a problem during the startup testing of the Unit 3 systems. The inspector reviewed the revisions to the Unit 3 FSAR descriptions for the IAS system, as documented in FSAR change request 97-MP3-425, noting that the capability to manually run the shutdown air compressors remained both a procedural (OP 3332A) and FSAR option.

At the time of the DCR M3-97005 implementation, an intent to implement future CCP cooling water modifications to the shutdown compressors was documented, which would have restored this IAS system to its original design capability. An engineering work request (EWR M3-97180) was initiated to correct the cooling water problem associated with the compressor operation. Subsequently, however, EWR M3-97180 was canceled; and a new EWR M3-98190, was issued instead, to implement the in-place abandonment of the shutdown IAS compressors, since they cannot be operated in accordance with the original design intent. As of the conclusion of this inspection report period, EWR M3-98190 remained open for implementation during a future cycle of operation.

While all of the design and licensing documents reviewed by the inspector were properly handled and consistent with the existing plant configuration and procedures, the inspector noted this situation creates a “nuisance” alarmed annunciator in the control room for a non-safety system that is not intended to ever function again. This condition was discussed with the IAS system engineer, who is currently exploring engineering options to remove such a “nuisance” annunciator from service, without creating other operational burdens, like a temporary modification, which would also have to be tracked. Opening the electrical supply breakers for compressors 3IAS-C2A & C2B, while currently being tracked as an abnormal configuration that is alarmed, actually represents a more “normal” unit configuration that has existed since the plant was licensed in 1985. The inspector also discussed with a cognizant engineer the IAS component labeling that differentiates the safety-related (*) electrical breakers from the non-safety compressors.

c. Conclusions

Review of the design change and licensing revision documents that support the current configuration of some non-safety instrument air system components revealed no deficiencies. This configuration does, however, result in the existence of an unnecessary “nuisance” annunciator in an alarmed state in the control room. The system engineer is currently evaluating various engineering options to remove this “nuisance” alarm for equipment not intended to be operated.

U3 E8 Miscellaneous Engineering Issues

E8.1 (Closed) LER 50-423/97-09-01; Open High Energy Line Break (HELB) Barrier Door in Mode 1 Results in Violation of HELB Requirements (92700)

The original licensee event report (LER) 50-423/97-07-00 was closed in NRC Inspection Report (IR) 50-423/97-02. As a result of the corrective actions identified in the original LER, the licensee found additional deficiencies and documented them in this LER supplement. The licensee initiated Condition Report (CR) M3-97-2567 to document these deficiencies and implement corrective actions. The inspectors noted that the resulting corrective actions were completed. There was no violation of regulatory requirements. **LER 50-423/97-09-01** is **closed**.

E8.2 (Closed) LER 50-423/98-007-01; Containment Bypass Leakage in Excess of Technical Specification Limits

With the unit in cold shutdown conditions in January 1998, the licensee identified that the containment bypass leakage limits specified in TS 3.6.1.2 had been historically exceeded during Cycle 2 (1988-89) of unit operation. This discovery was reported in LER 50-423/98-007-00 and was inspected by the NRC and documented as closed in inspection report 50-423/98-211. Subsequently, on April 9. 1998, the licensee transmitted a supplement (98-007-01) to this LER to the NRC.

During the current inspection, the inspector reviewed LER 98-007-01, noting that the only revisions in the supplement involved the discovery that the containment bypass leakage limits had also been exceeded during Cycle 3 of unit operation in the 1989-91 time frame and the discovery of nine additional bypass leakage pathways, which increased the identified leakage calculations for both cycles of operation. No additional regulatory requirements were affected. The cause of the event and corrective actions that were completed did not change. The inspector noted that the licensee addressed the corrective measures for the additional bypass leakage pathways.

LER 98-007-01 documents additional information on a historical condition prohibited by the plant TS. The licensee confirmed that the current potential containment bypass leakage is well within the required limits. The original LER was inspected and closed during a previous NRC team inspection, at which time enforcement action in the form of a violation was issued. This supplement only adds more historical information that affects neither the adequacy of past corrective actions, nor the current plant status in this regard. Therefore, **LER 50-423/98-007-01** is **closed**.

E8.3 (Closed) LERs 50-423/98-16-00,01&02; Potential Air/Gas Intrusion into the Chemical and Volume Control System

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of licensee event reports (LERs) 50-423/98-16-00, 01 & 02, Unit 3 technical specifications (TS), associated corrective actions documented in the licensee’s corrective action process, the Unit 3 Final Safety Analysis Report (FSAR), supporting codes and standards, and selected testing documentation.

b. Observations and Findings

On February 23, 1998, while Unit 3 was in Mode 5, the licensee identified several instances of gas binding in boric acid pumps or gas accumulation within the boric acid piping system. During these instances both the 'A' and 'B' pumps cavitated or became gas bound. The air binding of the boric acid pumps affected the capability of a boration pathway and resulted from a single cause. This condition was reported to the NRC pursuant to 10 CFR 50.73 (a)(2)(vii) as an event where a single condition caused two independent trains to become inoperable in a single system designed to shut down the reactor and maintain it in a safe shutdown condition. During the air binding of the boric acid pumps a boration path from the refueling water storage tank remained operable.

The licensee’s corrective actions included procedure updates, a TS change request, drawing changes, interim administrative controls (including routine venting of boric acid system piping) and the scheduling of permanent plant modifications. The permanent plant modifications were sufficiently planned at the time of this inspection to determine a good likelihood of correcting the problem, but implementation and testing were not inspected. The binding of the boric acid pumps resulted from an original plant design deficiency that was previously identified by the licensee but not adequately corrected. Failing to adequately establish and implement design controls to ensure that the single failure design basis assumptions for the boric acid system were correctly translated into specifications, drawings and procedures, is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. This failure was addressed by NRC Violation 50-423/97-82-06, which was adequately resolved and closed. Because the condition was 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 addressed in the licensee's corrective action system as Condition Report (CR) M3-98-0952, 0954, 0975, and 1539. The inspector determined that the licensee's interim administrative corrective actions were adequate. LERs 50-423/98-16-00, 01 & 02 are closed.

c. Conclusions

In 1998, the licensee reported historical instances where the Unit 3 boric acid pumps had been gas bound and the root cause of the binding had not been adequately corrected. The cause of the gas binding was an original plant design error which was reported and corrected by the licensee in 1998, as part of its response to an NRC violation. The licensee's interim, administrative corrective actions were adequate. **LERs 50-336/98-16-00, 01 & 02** are **closed**.

E8.4 (Closed) LER 50-423/99-07-00; Reactor Plant Aerated Drains Safety-Related Air Driven Sump Pump Design Deficiencies

a. Inspection Scope (92700)

The inspectors reviewed the event description, root cause analysis, and corrective actions associated with the licensee event report (LER) and interviewed the responsible system engineer.

b. Observations and Findings

In 1997, NNECO initiated a design change to the drain system to install safety-related air-driven sump pumps (P15A and P15B) in the containment recirculation cubicle sumps (S7A and S7B). The need for new pumps was identified during the FSAR design basis verification review. The new air-driven sump pumps were designed to discharge outside of the auxiliary building to a portable tank, and sumps S7A and S7B were required to be maintained clean (i.e., non-contaminated). The existing non-safety sump pumps (P8A and P8B) in sumps S7A and S7B discharged to sump S10 which also collected contaminated drains. The contaminated sump had a history of back-leakage into sumps S7A and S7B. To correct this problem and maintain sumps S7A and S7B clean, NNECO cut the discharge lines from P8A and 8B into sump S10 such that they ended above the sump high level setpoint.

In May 1999, during a health physics survey, the discharge filter for pump P8A was found to be contaminated. The root cause analysis determined that the contamination was due to back-leakage from sump S10. The corrective actions included further shortening of the discharge lines to above the top of the sump, to eliminate the siphon effect previously experienced.

The inspectors verified that the LER was completed in accordance with the requirements of 10CFR50.73. Specifically, the description and analysis of the event, as contained in the LER, were consistent with the inspectors' understanding of the event.

The root cause and corrective and preventive actions as described in the LER were reasonable. The LER is closed. Nonetheless, the failure to maintain sumps S7A and S7B clean placed the plant in a condition outside of the design basis. This is a violation of 10 CFR 50, Appendix B, Criterion III, “Design Control”. This violation is categorized at Severity Level IV and is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1.a of the NRC Enforcement Policy (NCV 50-423/2000-01-06). This violation is in the licensee’s corrective action program as CR M3-99-1769.

c. Conclusions

An inadequate design for part of the modification for the Unit 3 containment sump system resulted in contamination of one sump required to be maintained non-contaminated. This placed the plant in a condition outside of the design basis. The inadequate design was a violation of 10 CFR 50, Appendix B, Criterion III, which was categorized as Severity Level IV and treated as a Non-Cited Violation **(NCV 50-423/2000-01-06)**. **LER 50-423/99-07-00** is **closed**.

IV. Plant Support
(Common to Units 2 and 3)

R1 Radiological Protection and Chemistry Controls

R1.1 Technical Specification Required Secondary Chemistry Monitoring (79701)

The inspector conducted an on-site review of the Unit 2 secondary chemistry control program (CP2802B), Unit 2 technical specifications (TS), applicable supporting industry data (including the Electric Power Research Institute Secondary Water Chemistry Guidelines, Combustion Engineering Nuclear Steam Supply System Chemistry Manual), the Unit 2 Final Safety Analysis Report, and a selection of secondary chemistry testing documentation and data.

The Unit 2 secondary chemistry monitoring and maintenance program is required by TS 6.17, Secondary Chemistry, and is intended to minimize corrosion and assure the long term integrity of the steam generators. Based on the sample selected, the inspector determined that the licensee met the chemistry monitoring requirements of TS 6.17 and no violations of NRC requirements were identified.

R8 Miscellaneous Radiological Protection Issues

R8.1 (Closed) Unresolved Item (URI) 50-423/99-08-12; 7.04 REM TLD Exposure Event

a. Inspection Scope (83724)

The inspector reviewed the licensee's investigation into a reported 7.04 rem occupational exposure to a second quarter 1999 thermoluminescent dosimeter (TLD) personnel monitoring device assigned to a worker at the Millstone station. The review was against requirements contained in 10 CFR 20 and applicable licensee radiological controls program procedures.

b. Observations and Findings

On July 8, 1999, a second quarter 1999 personnel TLD indicated an apparent occupational dose of 7.04 rem during routine processing. This dose value was above the 10 CFR 20 Total Effective Dose Equivalent (TEDE) 5 rem annual limit and prompted an immediate licensee investigation. The licensee's initial investigation into the circumstances and probable cause of the 7.04 rem dose was conducted by the Radiation Protection (RP) technical staff and was considered thorough and comprehensive. This investigation concluded that the indicated dose to the TLD was valid. However, a time and motion study, conducted for the individual assigned the TLD, concluded that there was no credible means for this individual to have sustained the indicated dose. The time and motion study, in conjunction with actual dose data provided by secondary electronic dosimetry, indicated an actual dose to the individual assigned the TLD of 103 millirem. The investigation identified physical damage to the TLD badge suggesting tampering by an unknown person or persons. These investigation results were previously reported in Inspection Report 50-336, 423/99-08.

The licensee also conducted a preliminary security investigation to review the tampering issue. The investigation was inconclusive, as reported in Inspection Report 50-336, 423/99-09.

The licensee subsequently conducted and documented a final security investigation. The in-office review of this report, dated November 14, 1999, by an NRC Region I staff specialist concluded that there was convincing evidence that an unknown person or persons had tampered with the TLD. There was, however, no evidence to implicate any specific individual(s).

Based on the NRC review of the security investigation reports and radiation protection staff reports, a credible and adequate investigation had been conducted of circumstances and cause of the elevated TLD dose and the likely cause of the dose was deliberate tampering and irradiation of the TLD.

Notwithstanding, the licensee did initiate corrective measures to address possible contributing and potential causes. For example, the licensee is evaluating methods to improve (1) the control and accountability of personnel TLDs when not in use; (2) the distinction between TLDs that may be used for exposure experiments and measurements versus personnel monitoring applications; and (3) the positive identification of TLDs assigned to personnel upon entry to the Radiologically Controlled Area. These corrective action evaluations were documented in the licensee’s corrective action system (CR M3-99-2642). No violations of regulatory requirements were identified. Therefore, **URI 50-423/99-08-12** is **closed**.

c. Conclusions

The licensee’s investigations into the circumstances and probable causes of a reported 7.04 rem occupational dose to a personnel TLD in the second quarter of 1999 concluded that the dose to the badge was valid. However, the investigations further concluded that the dose was most likely caused by tampering and deliberate exposure of the TLD badge by an unknown person or persons, and that the individual assigned the TLD badge had not received such an occupational dose. The licensee took corrective actions to preclude recurrence. No violations of regulatory requirements were identified.

S1 Conduct of Security and Safeguards Activities

S1.1 Station Security Observations

While conducting inspection-tours of the protected area, the inspector conducted a visual inspection of the entire fence line, taking particular note where the protected area boundary fencing ties in with existing buildings. The inspector also checked some visitor escort controls for contractor truck drivers making deliveries to the site. During one inspection-tour, the inspector noted the security diesel generator enclosure open with the generator running. Discussion with security personnel revealed that the generator was being used to provide power to the technical support center. Under those conditions, the security enclosure had been appropriately de-vitalized. Security guard compensation for other vital areas was noted as appropriate, where the boundaries had been opened to support existing work or where degraded conditions had been identified. The inspector had no questions or concerns regarding the observations made during these plant inspection-tours.

S3 Security and Safeguards Procedures and Documentation

S3.1 Review of Selected Security Procedures

During the review of NRC Unresolved Item 50-245/97-02-02, which was documented as closed in NRC Inspection Report 50-245/336/423/99-09, the inspector identified that specific corrective actions regarding security procedure revisions provided incomplete guidance as required by the proposed corrective action. Specifically, Security Department Instruction (SDI) 612, “Security Reports,” contained instructions to assist various security personnel in the initiation of condition reports and licensee event reports, as well as emergency plan implementation for safeguards events. As was noted during previous inspection, the guidance contained in SDI 612 was inconsistent with the applicable site-related programs or procedures, i.e., RP-4, “Corrective Action Program,” for condition report initiation. The inspector discussed these inconsistencies with cognizant licensee security department personnel. During the current inspection, the inspector reviewed the licensee’s subsequent revisions to the SDIs and found them to be acceptable.

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.

INSPECTION PROCEDURES USED

IP 37550	Engineering
IP 37551	Onsite Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Program
IP 71707	Plant Operations
IP 79701	LWR Water Chemistry Control and Chemical Analysis - Program
IP 83724	External Occupational Exposure Control and Personal Dosimetry
IP 90712	In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92700	Onsite Follow-Up of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92702	Followup on Corrective Actions for Violations and Deviations
IP 92901	Follow-up - Operations
IP 92903	Follow-up - Engineering
IP 93702	Prompt Onsite Response to Events at Operating Power Reactors
TI 2115/142	Draindown During Shutdown and Common-Mode Failure (NRC Generic Letter 98-02)

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-336/2000-01-01	NCV	Failure to Adequately Implement Surveillances for Engineered Safety Feature Actuation System Instrumentation and Meteorological Monitoring Instrumentation (related to LER 50-336/98-08-00)
50-336/2000-01-02	NCV	Failure to Establish an Adequate Surveillance Procedure for Testing the Enclosure Building (related to LER 50-336/98-010-00)
50-336/2000-01-03	NCV	Design Control Deficiency Involving Isolation of Main Feedwater (related to LER 50-336/98-011-00)
50-336/2000-01-04	NCV	Design Control Deficiency Involving Potential to Exceed SDC System Design Pressure (related to LER 50-336/98-013-00)
50-336/2000-01-05	NCV	Design Control Deficiency Involving Blocking Open Doors in Control Room Ventilation Boundary (related to 50-336/98-014-00)
50-423/2000-01-06	NCV	Design Control Deficiency Results in Contamination of Containment Sump Required to be Maintained Clean (related to LER 50-423/99-07-00)

Closed

The NCVs opened above are closed.

50-336,423/97-01-03	URI	Inaccurate Personnel Qualification Statements
50-336/97-202-02	URI	Main Steam Check Valves
50-336,423/97-202-06	EEI	Maintenance and Technical Training
50-423/97-82-03	IFI	Organizational Independence of Human Factor Engineering Personnel
50-423/97-82-04	IFI	Corrective Action Program Lacked Controls
50-423/97-82-09	IFI	Quality Lacking in the Setpoint Control Program
50-423/97-83-05	IFI	Qualification of Fire Brigade Supervisor and Members
50-423/98-207-14	IFI	Corrosion Control for Closed Cooling Water Systems
50-423/99-02-05	IFI	Containment Radiation Monitor Design Basis Function
50-423/99-08-12	URI	7.04 REM TLD Exposure Event

The following LERs were also closed during this inspection:

LER 50-336/98-05-00, 01, & 02	High Energy Line Break
LER 50-336/98-08-00	Technical Specification Violations
LER 50-336/98-010-00	Analysis of Enclosure Building Stack Effects
LER 50-336/98-011-00	Feedwater Valve Closure
LER 50-336/98-013-00	Shutdown Cooling System Operations
LER 50-336/98-014-00	Control Room Ventilation Boundary Operations
LER 50-336/98-017-00 & 01	Fire Protection Program Deficiencies
LER 50-336/99-014-00	Failure to Enter Limiting Condition for Operation While Testing a Containment Isolation Valve

LER 50-336/99-015-00	Unanticipated Reactor Protection System Trip Signal on Low Steam Generator Level
LER 50-336/99-016-00	Technical Specification Surveillance Requirements of Seismic Instrumentation Were Not Historically Met
LER 50-336/2000-001-00	Manual Reactor Trip due to Low Steam Generator Level Following a Feedwater Heater Level Transient
LER 50-423/96-21-02	Components Not Included in the Inservice Test Program
LER 50-423/97-09-01	Open High Energy Line Break (HELB) Barrier Door in Mode 1 Results in Violation of HELB Requirements (92700)
LER 50-423/98-007-01	Containment Bypass Leakage in Excess of Technical Specification Limits
LER 50-423/98-16-00,01, & 02	Potential Air/Gas Intrusion into the Chemical and Volume Control System
LER 50-423/99-02-00	Inadvertent Carbon Dioxide Fire Suppression System Actuation in the Cable Spreading Room
LER 50-423/99-07-00	Reactor Plant Aerated Drains Safety-Related Air Driven Sump Pump Design Deficiencies

LIST OF ACRONYMS USED

ACR	adverse condition report
ASME	American Society of Mechanical Engineers
ASTM	American Society of Testing Methods
AWO	automated work order
CAL	confirmatory action letter
CAP	corrective action plan
CCE	charging pump cooling water
CCI	safety injection pump cooling water
CCP	component cooling water
CO_2	carbon dioxide
CP	control program
CR	condition report
ECCS	emergency core cooling system
EEI	escalated enforcement item(s)
EPRI	Electric Power Research Institute
FSAR	Final Safety Analysis Report
GL	generic letter
HELB	high energy line break
HFE	Human Factor Engineering
HPSI	high pressure safety injection
I & C	instrumentation and control
IAS	instrument air system
IFI	inspector follow-up
IR	inspection report
ISEG	Independent Safety Evaluation Group
IST	inservice testing
LCO	limiting condition for operation
LER	licensee event report
MSIV	main steam isolation valve
MSLB	main steam line break
NCV	non cited violation
NNECO	Northeast Nuclear Energy Company
OD	operability determination
PEO	plant equipment operator
PORC	plant operations review committee
PWR	pressurized water reactor
RCS	reactor coolant system
RHR	residual heat removal
RPCCW	reactor plant chilled cooling water
RP	radiation protection
RPS	reactor protection system
RWST	refueling water storage tank
SAT	systems approach training
SBO	station blackout
SCBA	self contained breathing apparatus
SDC	shutdown cooling system

SDI	Security Department Instruction
TDAFW	turbine driven auxiliary feedwater
TEDE	Total Effective Dose Equivalent
TLD	thermoluminescent dosimeter
TS	technical specifications
UPS	uninterruptible power supply
URI	unresolved item