U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.: 50-245/89-25 and 50-336/89-23

Docket Nos.: 50-245; 50-336

License Nos. DPR-21; DPR-65

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

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

Inspection at: Waterford, Connecticut

Dates: October 21 - December 4, 1989

Reporting Inspector: P. J. Habighorst, Resident Inspector

Inspectors: W.J. Raymond, Senior Resident Inspector, Millstone Station
P.J. Habighorst, Resident Inspector, Millstone Unit 2
D.A. Dempsey, Resident Inspector, Millstone Unit 1
G. Vissing, Project Manager, Project Directorate I-4, Office of Nuclear Reactor Regulation

Approved by: Donald R. Haverkamp — 1/18/90
Donald R. Haverkamp, Chief — Date
Reactor Projects Section 4A
Division of Reactor Projects

Inspection Summary: Combined Inspection Reports Nos. 50-245/89-25; 50-336/89-23

Areas Inspected: Routine NRC resident inspection of plant operations, surveillance, maintenance, previously identified items, engineering/technical support, committee activities, evaluation of licensee self-assessment, security, allegations, and radiological controls.

Results:

1. General Conclusions on Adequacy, Strength or Weakness in Licensee Programs

The overall operations control during the observed plant evolutions were effectively implemented and is considered a strength. (Section 3.3.2)

A strength was noted in problem identification of the seismic supports for the service water strainers, classification of the associated Unusual Event, and control of plant activities during the Unusual Event at Unit 2. (Section 3.5.1)

Two events involving check valve failures in safety-related applications on Millstone 1 and 2 highlight the need to improve the program to assure continued check valve operability and acceptable performance. (Sections 3.6, 5.1.2, 5.1.3, and 6.2)

2. Unresolved Items

Millstone 1

Three previously unresolved items and one open item were closed. (Sections 5.5.1, 6.6.1, 6.6.2, and 9.5.1)

Three unresolved items were opened regarding: (1) the acceptability of some of the accident mitigation strategies in the emergency operating procedures (Section 3.8); (2) feedwater coolant injection system operability on loss of air to the minimum flow valves, and licensee reporting of the issue (Section 3.9); and, (3) the upgrade of programs to improve performance of check valves in safety-related applications. (Section 6.2)

Millstone 2

Three unresolved items were opened regarding: (1) acceptability of design margins in seismic supports (Section 6.5); (2) the upgrade of programs to improve performance of check valves in safety-related applications (Section 6.2); and (3) evaluation of environmental qualifications for valve 2-FW-12B, the auxiliary feedwater discharge valve solenoid operator (Section 9.4).

3. Allegations

Several concerns received from workers since July 1989 were inspected upon receipt and/or referred to the licensee for resolution, if appropriate. On November 8 and December 4, a summary of the concerns was formally presented to license management for resolution. The issues are listed in the appendix to this report. Licensee responsiveness to employee concerns will be reviewed further on subsequent inspections. (Section 9.1).

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

*The NRC inspection manual inspection procedure (IP) or temporary instructions (TI) that was used as inspection guidance is listed for each applicable report section.

DETAILS

1.0 Persons Contacted

Interviews and discussions were conducted with licensee staff and management during the report period to obtain information pertinent to the areas inspected.

Inspection findings were discussed periodically with the supervisory and management personnel identified below.

S. Scace, Millstone Station Superintendent
#J. Stetz, Unit 1 Superintendent
N. Bergh, Unit 1 Maintenance Supervisor
W. Vogel, Unit 1 Engineering Supervisor
P. Prezkop, Unit 1 Instrument and Controls Supervisor
R. Palmieri, Unit 1 Operations Supervisor
*J. Keenan, Unit 2 Superintendent
J. Riley, Unit 2 Maintenance Supervisor
F. Dacimo, Unit 2 Engineering Supervisor
J. Becker, Unit 2 Instrument and Controls Supervisor
J. Smith, Unit 2 Operations Supervisor

Attendee at post-inspection exit meeting on December 21 for Unit 2,(*) and January 5, for Unit 1 (#).

2.0 Summary of Facility Activities

Millstone 1

On October 19, 1989, the reactor scrammed as a result of a failure of the "A" feedwater regulating valve. The plant restart commenced on October 22 following repairs, and the reactor was taken critical at 12:55 a.m. on October 23. Routine startup and test activities continued while the reactor was critical between October 23 to 25; actions were taken to repair leaks in the steam jet air ejectors and to replace a leaky gasket on the turbine gland seal regulator. Startup continued on October 24 and the turbine-generator was placed on line at 12:50 p.m. and full power was attained at 6:00 p.m. that same day.

Routine plant operations continued until November 9 when power was reduced to 85% rated for routine turbine stop valve testing. During the power decrease, the "A" feedwater regulating valve stuck in the open position. The licensee further reduced plant power to 70% rated until the valve body was opened and a loose part (feedwater check valve locking plate) was retrieved. The feedwater regulating valve was inspected and re-assembled and full power operation resumed at 11:45 p.m. on November 9.

Power was reduced to 70% on November 16 to complete routine turbine testing and to repair a tube leak in the "D" main condenser water box. Routine full power operation and periodic testing continued until November 28, when a reactor recirculation pump 'A' runback to minimum speed occurred, resulting in a reactor power decrease to 76%. While repair efforts were in progress, operators took local-manual control of the pump motor-generator speed controller. Full power operation was achieved within one hour of the controller failure, and continued for the remainder of the inspection period.

Millstone 2

At the beginning of the inspection period, plant power was being reduced for a scheduled mid-cycle outage. The primary focus for the outage was non-destructive examinations of the steam generator tubes. At 2:48 a.m. on October 21, the main turbine was taken off line and at 1:40 a.m. on October 22 the reactor was placed on the shutdown cooling system.

On November 9, at 7:25 p.m. the licensee declared an Unusual Event based on inoperability of the emergency diesel generators. The diesel generators were declared inoperable based on a calculated inadequate safety margin for the service water strainer supports during a seismic event. The unit exited the Unusual Event on November 14 at 3:15 a.m. after completion of support modifications. Review of the Unusual Event is described in detail 3.5.1 of this report.

On November 23, at approximately 12:23 p.m., the main turbine was placed in service, and on November 25, the unit resumed full power operations, and remained at that power level until the end of the inspection period. Major outage activities are described in detail 3.3.2.

NRC Activities

Routine resident and specialist inspection involved 283 regular hours, 80 backshift hours, and 33 deep backshift hours.

A Region I specialist inspection of the Millstone 2 steam generator eddy current program was conducted on November 7-9, 1989. Results are reported in inspection report 50-336/89-20.

A Region I specialist inspection of the Millstone 1 quality assurance program was conducted on December 4-8, 1989. Results are reported in inspection report 50-245/89-21.

A Region I specialist inspection of Millstone 1 emergency operating procedure plant specific technical guidelines was conducted on October 23-27, 1989. Results are reported in inspection report 50-245/89-18.

3.0 Plant Operations

3.1 Control Room Observations

Control room instruments were observed for correlation between channels, proper functioning, and conformance with Technical Specifications. Alarm conditions in effect and alarms received in the control room were discussed with operators. The inspector periodically reviewed the night order log, tagout log, plant incident report log, key log, and bypass jumper log. Each log was discussed with operation department staff. No inadequacies were noted.

3.2 Plant Tours - Units 1 and 2

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

Unit 1:

Control Room	Station Battery Rooms
Gas Turbine Generator Building	Reactor Building
Diesel Generator Room	Service Water Intake Structure

Unit 2:

Control Room	Containment
Vital Switchgear Room	Diesel Generator Room
Turbine Buildings	Intake Structure
Enclosure Building	ESF Cubicles

During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication of equipment status.

While touring the Unit 1 reactor building on November 28, 1989, the inspector observed that the fuel pool cooling and cleanup system was operating in a "manual" mode with the following alarm conditions:

- Demineralizer [effluent] strainer differential pressure high (>10 psid)
- Influent conductivity high (>0.1 micromho/cm)
- Effluent conductivity high (>0.1 micromho/cm)

In the automatic mode of operation, these conditions would cause the system demineralizer to be isolated and bypassed. The inspector reviewed operating procedure OP 310, Fuel Pool System, Revision 16, dated May 25, 1989, and could find no procedure steps which specifically addressed system operation in "manual."

The inspector discussed the condition of the system with operations and chemistry department personnel and ascertained that the conductivity monitoring system was not in use due to flow cell problems, and that the strainer alarm condition persisted even after cleaning. The inspector confirmed that appropriate sampling and analysis of system water was performed and that the existing mode of operation presented no safety concerns.

During a walkdown of the Unit 1 service water intake structure, the inspector noted a wooden wedge inserted in spring can hanger CCS-H-3 which would block upward movement of the "C" emergency service water pump discharge line. This hanger had been inspected satisfactorily as part of the licensee inservice inspection (ISI) program during the 1987 refueling outage. When notified by the inspector, the licensee initiated plant incident report 1-89-89, dated November 27, 1989, removed the wedge, and performed an inspection of other spring can hangers in the service water structure. No further anomalies were discovered. Licensee followup determined that the hanger is designed only for dead weight and thermal expansion, and performs no credited seismic function. The inspector had no further questions.

3.3 Control of Plant Startup

3.3.1 Estimated Critical Position Discrepancy - Unit 2

On November 20, the licensee calculated an estimated critical position (ECP) to achieve reactor criticality. The ECP supported reactor startup from the mid-cycle outage which began on October 21. The estimated critical position was a control rod configuration of group 7 at 90 steps, with reactor coolant system boron concentration at 1013 parts per million (ppm). The critical position was estimated based on hot full power reactor critical conditions on October 19. At 4:24 a.m., on November 22, the control room operators established the desired critical boron concentration, and withdrew all control element assemblies to the all rod out configuration without achieving criticality.

At 5:10 a.m., all regulating group control element assemblies were inserted and shut down margin was verified as required in procedure OP-2202.

The acceptance criteria for control element position at criticality is ± .9% delta K/K as prescribed in procedure OP-2208. Based on the reactivity balance for the hot full power data, the actual achievable acceptance criteria was +.9% delta K/K (rod position group 5 step 144) and -.38% delta K/K (all control element assemblies fully withdrawn).

At 9:30 a.m., the Plant Operations Review Committee (PORC) reviewed the cause for the potential estimated critical position discrepancies. Reactor engineering provided potential reasons for not achieving criticality. The explanation included potential minor errors in fuel temperature defect curves, samarium defect curves, and xenon defect curves supplied from the fuel vendor. The licensee revised the initial estimated critical position calculation using the hot zero power reference data of April 28, 1989. The only hot zero power reference critical position for the current operating cycle was on April 28, 1989. The primary differences of estimated critical position calculations were fuel temperature defect, xenon defect, and integral control element assembly worth. The revised calculation estimated criticality at a boron concentration of 953 ppm, with the same rod configuration as the initial calculation (Group 7 at 90 steps).

The inspector reviewed the initial and final ECP calculations with procedure OP-2208 and identified no inadequacies in the licensee's calculation. Reactor criticality was achieved at 12:00 noon on November 22 with a control rod pattern with group 7 at 40 steps and a boron concentration of 948 ppm. The inspector observed the approach to criticality, and reactor engineering 1/M plots during the approach.

The inspector independently calculated the actual reactivity balance uncertainities based on reactivity worth graphs depicted in procedure OP-2208, with the following conclusions: (1) the error on the first ECP was in excess of -.38% delta K/K with a last recorded 1/M plot of .05; (2) the error on the second ECP was calculated to be +.3001% delta K/K; and (3) the error on combination of the initial ECP and actual critical values on the second attempt to criticality was .3749% delta K/K. Based on the above, the licensee was within the allowable acceptance criteria (+/- .9% delta K/K) of the controlling procedure to calculate the critical rod position.

The licensee intends to send the as found critical data for the November 22 startup to the fuel vendor to consider revisions to reactivity graphs as necessary.

A review of reporting requirements under 10CFR 50.72, NRC Regulatory Guide 10.1 and the licensee's administrative control procedure concluded no reports were required.

In conclusion, the licensee corrective actions on the failure to initially achieve reactor criticality were appropriate. Good control was observed during the reactor start-up, and no unsafe actions or conditions were observed.

3.3.2 Outage Activities and Plant Start-up - Unit 2

The primary focus of the mid-cycle outage was non-destructive examination of steam generator tubes, and repair of mechanical tube plugs using a plug-in-plug design. The facility commenced a plant shutdown on October 20 at 10:00 p.m., and the planned outage duration schedule was 32 days from 100% to 100% rated power.

The licensee maintained operations as the focal point during the outage and the department was heavily involved in controlling the outage activities. An efficient outage organization comprised of an experienced shift supervisor and a team of operators provided plant configuration control.

Unit staff meetings were generally twice per day on weekdays; weekend meetings were also held between designated management representatives. The meetings offered accurate planning updates, kept unit personnel aware of plant status, and promoted effective communications between unit departments. Management provided clear and frequent direction on the unit goals and gave timely feedback to unit personnel. The outage scheduling group provided a positive contribution through detailed printed schedules which were maintained on a computer base and generally served to further assure personnel awareness. Cooperation between departments was exemplary. Continuous management representative coverage, a position filled by department heads or other management personnel, was effective in timely problem resolution.

Health physics staffing was increased by use of contractor personnel and an effective outage organization was established. The inspectors routinely reviewed radiological controls and found the field technicians to be knowledgeable and dedicated.

The major planned modification activities accomplished by the licensee were:

-- 'A' reactor coolant pump motor replacement. Work activities included replacement of the motor, installation of a new seal [illegible] 9000) per plant design change record (PDCR) 2-36-88, and flywheel in-service inspection.

-- Steam generator (SG) work activities. The SG activities included eddy current testing; repair of susceptible tube plugs per PDCR 2-018-89; removal of three SG tubes for destructive/non-destructive examination and testing per PDCR 2-19-89; and, SG tube repair based on eddy current testing results per PDCR 2-017-89. A specialist NRC inspection (50-336/89-20) reviewed the SG eddy current testing, and inspector review of SG repair activities identified acceptable conditions, and an aggressive interface between contractors, unit staff, corporate engineering, and vendors. Inspector review of PDCR development and implementation identified no inadequacies.

-- Pressurizer heater weld inspection. The inspection is further documented in report detail 6.4.1.

-- Emergency diesel generator rework of injectors, replacement of voltage regulator, electronic governor box, and exhaust fire penetration seals. The activities in general were to address corrective maintenance to specifically enhance the "A" emergency diesel generator reliability in response to concerns described in Inspection Report 50-336/89-17.

-- Reactor coolant system resistance temperature detector replacements, cross-calibrations, and response time testing.

Activities identified during the plant outage and addressed by the licensee included: repair of high pressure safety injection check valve (2-SI-247) body-to-bonnet leakage; 'A' control room exhaust fan repair; repair of service water leaks on the turbine building component cooling water heat exchangers; repair of environmental qualification deficiencies on the auxiliary feedwater check valve (2-FW-12B); installation of seismic supports for the service water strainers; and, repair and successful retesting of the No. 2 main turbine control valve. Good problem identification and repair was noted for the selected outage-identified activities.

The estimated mid-cycle outage exposure was established at 250 man-rem. Approximately 38% of the expected exposure was a result of SG work (i.e. nozzle dam installation, eddy current testing, plug repair, and tube pull). At the daily planning meeting, major work activity exposure results were presented to utility management and were discussed to identify exposure reduction alternatives. The final mid-cycle outage exposure was 257.9 man-rem. The inspector observed good health physics assistance and control, specifically in the SG plenum work, pressurizer heater inspection, and containment inspection during heat-up evolutions to maintain personnel exposure as low as reasonable achievable.

Control room operator involvement in control of plant conditions was reviewed by the inspector during the outage. Specific activities included the controls during reduced inventory operation; plant restoration, heat-up, and startup pre-requisites; reactor start-up; control of equipment and adherence to LCO requirements during the Unusual Event discussed in Section 3.5.1; and, conformance to technical specification requirements for startup and operation in Mode 1. The overall operations control during the observed plant evolutions were effectively implemented and is considered a strength.

3.4 Review of Plant Incident Reports - Units 1 and 2

The plant incident reports (PIRs) listed below were reviewed during the inspection period to (i) determine the significance of the events; (ii) review the licensee's evaluation of the events; (iii) verify the licensee's response and corrective actions were proper; and, (iv) verify that the licensee reported the events in accordance with applicable requirements. The PIRs reviewed were:

Millstone 1

- 1-89-78 - Reactor Scram Due to Feedwater Regulating Valve Failure
- 1-89-32 - Leaks in Service Water Piping in Strainer Pit
- 1-89-83 - Failure of the 'A' Feedwater Regulating Valve
- 1-89-84 - Sticking "B" Reactor Protection System Scram Relay Reset
- 1-89-85 - "D" Service Water Pump Seal Water
- 1-89-86 - "A" Feedwater Regulating Valve Failure
- 1-89-87 - Reactor Feed Pump Minimum Flow Valve Postulated Loss of Air
- 1-89-88 - Fire at Sullair Compressor Enclosure
- 1-89-89 - Wooden Wedge Found in Spring Can Hanger CCS-H-3
- 1-89-90 - Main Steam Line Radiation Alarm During Reactor Feed Pump Shift
- 1-89-91 - "A" Recirculation Pump Motor-Generator Speed Control Failure
- 1-89-92 - Loss of Meteorological Data Acquisition Tower

Millstone 2

- 2-89-110 - Plant Shutdown for Steam Generator Tube Inspection
- 2-89-113 - Radiation Monitor 8262A/B Inlet Valve Closed
- 2-89-115 - Auxiliary Feedwater Discharge Check Valve (2-FW-12B) Operator Failed to Stroke
- 2-89-119 - Lack of Electrical Equipment Qualification for Valve 2-FW-12B
- 2-89-120 - Unusual Event Based on Both Emergency Diesels Inoperable

The following topics of PIRs generated at Unit 1 are documented further in other sections of this report: reactor scram due to feedwater regulating valve failure (Section 3.6); failure of the "A" feedwater regulating valve (Sections 5.1.1 and 5.1.2); wedge located in spring can hanger CCS-H-3 (Section 3.2); and "A" recirculation pump motor-generator speed control failure (Section 3.10). At Unit 2, the following topics of PIRs were documented further in other sections of this report: plant shutdown for steam generator inspection (Sections 3.3.2 and 6.4.2); lack of electrical equipment qualification for valve 2-FW-12B (Section 9.4), and the emergency classification (Unusual Event) for diesel generator inoperability (Section 3.5.1). No further questions developed on PIRs for both units not specifically described above.

3.5 Onsite Followup of Operational Events

3.5.1 Inoperable Service Water System Due to Seismically Unqualified Strainers - Unit 2

The licensee informed the resident inspector at 7:30 p.m. on November 9, of action in progress to meet technical specifications (TS) limiting conditions for operation (LCO) due to an inoperable condition on the redundant service water headers. The plant was in cold shutdown at the time with the reactor coolant loops drained to support steam generator tube inspection and plugging activities. Water level in the reactor was 71 inches above the center line of the hot leg and was stable. The pressurizer manway was removed for overpressure protection in accordance with the requirements of TS 3.4.9.3. The service water system remained functional and in operation to support all normal shutdown cooling loads, but was considered by the licensee to be administratively inoperable as a result of a seismic analysis for the service water strainers.

The licensee's unit staff was informed on November 9 by corporate engineering that the results of a re-analysis of the supports for the service water strainers found them to be inadequate to meet stress load limits in the event of an earthquake. The re-analysis was conducted during the week of November 6 after an internal quality assurance audit found errors in the original seismic calculations for the strainers and the associated pump discharge headers. Specifically, the strainer support hold down bolts were found to have less than the required design margin for a seismic event (safety factor of four to the ultimate stress limits) for the type of anchor bolts (Hilti) used. The bolts were acceptable for normal operational stress loads.

The Millstone 2 service water system consists of three pumps at the intake structure which discharge through associated strainers to a common discharge header. Only two of three pumps are needed to support cooling for full power operation and are required to be operable per the technical specifications. Since all three strainers were affected and since the strainers in turn provide partial support for the redundant service water header, the licensee considered both Facility I and II service water systems to be administratively inoperable.

The service water system is a support system for a number of other safety systems. The following systems were affected by the service water system inoperability and were also considered inoperable: both loops of shutdown cooling and emergency diesel generators. The licensee took actions to implement the appropriate TS action statements for the associated equipment. When emergency power supplies are inoperable during plant operations at power, the TS do not require entrance into the individual LCOs for the affected equipment. This provision does not apply for cold shutdown operations.

The inspector reviewed licensee actions in progress during the evening of November 9 to identify the LCOs impacted by the inoperable equipment and to implement the associated action statements. Licensee action for the following system and component requirements were reviewed: TS 3.1.2.1 - Boration flow paths; TS 3.8.1.2 - AC power sources; TS 3.1.2.3 - operable charging pumps; TS 3.8.2.2 - AC distribution onsite; TS 3.9.15 - fuel storage pool area ventilation; TS 3.7.6.1b - control room air conditioning; and, TS 3.4.1.3 shutdown cooling loops. Containment integrity was required to meet TS 3.8.2.2 and actions were taken to assure that the personnel air lock was secured, containment penetrations were secured or isolable, and work on a feedwater check valve was terminated and the valve was closed to secure a potential leakage path through the open steam generator water boxes and tubes that had been cut but were not yet plugged. However, complete closure of the containment per the operability definition was not provided and is discussed further in Section 3.5.2 below.

Because both emergency diesel generators were considered administratively inoperable and no action could be taken per the technical specifications to restore a diesel to an operable status within two hours, the licensee declared an Unusual Event at 7:25 p.m. in accordance with the emergency plan and the following emergency action levels: both diesel generators inoperable for greater than two hours; identification of an unanalyzed condition which placed the plant outside the design basis; and the existence of a plant status condition that warranted increased awareness by plant personnel and offsite authorities. The NRC Duty Officer was notified. No inadequacies were identified in meeting the emergency plan and notification requirements.

The inspector also reviewed plant status on November 9 and the plant systems aligned to support cold shutdown operations. Inspector review confirmed that the plant status was stable and equipment was available to support core cooling. No unsafe plant conditions were identified. The reserve station service transformer was out of service for preventive maintenance, but plant loads remained energized by back feeding from the 345 KV switchyard using the main transformer. The emergency diesel generators remained available for operation. In most cases for the "degraded" equipment conditions, the required technical specification actions were to suspend core alterations (none were in progress), and to not perform actions that would result in a positive reactivity change. The inspector identified no inadequacies in licensee actions to meet technical specification action statements. Operator reviews in this matter were thorough, showed an excellent knowledge of work activities in progress and the impact on plant system status, and an excellent regard for reactor safety.

The plant remained in an Unusual Event emergency condition while modifications were completed to the service water strainer supports. The plant terminated the Unusual Event condition on November 14 upon completion of repairs. Refer to Section 6.5 below for further NRC review of the seismic calculations involved in the original and revised strainer supports. The basis for system operability and continued plant operation is also provided below.

3.5.2 Enforcement Discretion Regarding Containment Integrity when the Emergency Diesel Generators were Inoperable - Unit 2

The licensee requested on November 9 that the NRC staff approve a deviation from the plant technical specifications regarding complete containment closure. The licensee requested that the NRC approve actions to not completely close the containment equipment hatch and to accept an alternate plan for assuring full closure if conditions required such action. The reason for the request was to allow the continuation of work activities in progress to repair the open steam generators, which relied on the passage of electrical power and hoses through the hatch. The licensee requested and presented the basis for deviation from the technical specifications in a letter dated November 9, 1989.

This matter was discussed with the resident inspector, NRC Office of Nuclear Reactor Regulation personnel, and NRC Region I personnel. NRC Region I gave verbal approval of the request during a conference call with the licensee at 12:15 a.m. on November 10, which was prior to the expiration of the TS 3.8.2.2. 8-hour action statement. Written approval was provided by NRC Region I letter dated November 10, in which the NRC staff granted a one-time enforcement discretion regarding containment integrity requirements specifically due to the administrative inoperability of the emergency diesel generators that occurred at 6:45 p.m. on November 9, when the service water pump discharge strainers were determined analytically to be not qualified to appropriate seismic criteria.

Specifically, the enforcement discretion granted relief from Millstone 2 TS 3.8.2.2, "AC Distribution - Shutdown", to establish containment integrity per TS 1.8.2 regarding closure and sealing of the containment equipment hatch within eight hours from the loss of diesel operability. In lieu of full closure of the hatch, the licensee proposed to implement procedures and administrative controls established in response to Generic Letter

88-17 "Loss of Decay Heat Removal" that would assure containment closure within 122 minutes following a loss of shutdown cooling. The licensee further committed to keeping the electrical buses referenced in TS 3.8.2.2 energized from sources of power other than a diesel generator, while keeping diesel generator power available to the buses. The enforcement discretion specifically applied to the alternate method of containment closure and authorized an extension of the time the plant may continue with cold shutdown activities without full containment closure while the diesels were inoperable.

The deviation from the TS was acceptable because: the existence of a potentially degraded condition required the unlikely occurrence of a seismic event; the actual plant status was stable and all cooling needs were being met by an operating service water system; the continuation of work activities to repair the steam generators and return the RCS loops to an operable status would serve to further plant stability and safety; and, licensee procedures and administrative controls were sufficient to assure that full containment closure could be obtained upon demand in a timely manner - relative to the analyzed occurrence of a loss of shutdown cooling causing boil off of reactor water cooling the core.

The enforcement discretion was effective until 5:00 p.m., Tuesday, November 14, 1989. The licensee completed modifications on the strainers by adding additional seismic supports to the discharge nozzles of each of the three strainers. The licensee declared both diesel generators operable and exited the action statements at 3:15 a.m. on November 14. NRC review of the modifications is discussed further in Engineering Technical Support Section 6.5 below.

The inspector reviewed licensee actions on November 10 to implement commitments to secure the containment. The personnel air lock was secured by closing at least one door. The containment liner closure hatch was rolled in place but held open about four inches by wood blocks to allow the passage of cables and hoses. Four temporary bolts were in place to allow closure of the hatch if required. A designated crew consisting of operations, electrical maintenance and mechanical maintenance personnel were available onsite to complete the necessary action to close the hatch if directed by the shift supervisor.

The inspector had no further comments regarding licensee actions for TS 3.8.2.2. No inadequacies were identified.

3.6 Reactor Scram on October 19, 1989 due to Feedwater Regulating Valve Failure - Unit 1

3.6.1 Summary

On October 19, a power reduction to 50% was made primarily to repack the "B" feedwater regulating valve (FRV). Upon completion of repairs, plant operators increased power to about 70% full power (FP) using the reactor recirculation system and made preparations to place the "B" feedwater train in service. The plant was operating with the "A" FRV in automatic and controlling vessel level. While placing the "B" FRV in service the "A" FRV failed full open, causing vessel level to increase to the high level trip setpoint. The main turbine tripped at 3:16 p.m. on high vessel level (+48 inches), followed immediately by an automatic reactor trip. An NRC inspector was in the control room at the time and monitored the licensee's response to the scram.

Plant operators stabilized the reactor in hot shutdown. The turbine bypass valves were used to maintain reactor pressure control and vessel level was stabilized in the normal control band using the reactor water cleanup system and the feedwater system on the startup feedwater regulating valves. The plant response to the scram was normal. Except for the "A" FRV, all safety and other plant systems functioned as required.

The event was reported to the NRC at 3:40 p.m. as required by 10 CFR 50.72(b)(2)(ii). The inspector monitored the report to the NRC headquarters operations officer by the Millstone 1 shift supervisor staff assistant. The report was accurate regarding the event and plant status. Detailed NRC questions on plant response, event cause and corrective action plans were referred to the operations shift supervisor as required. No inadequacies were identified.

The "A" FRV was removed following draining and cooldown of the header. A 7/8-inch bolt was found under the "A" FRV seat. The licensee determined that the bolt came from the "A" feedwater pump discharge check valve FW-2A. The Crane check valve normally has two valve seat hold-down bolts with a lock wire keeper assembly. One of the two bolts was missing from valve FW-2A and the second bolt along with its keeper assembly was loose. The licensee inspected the discharge check valves for the B and C feedwater pumps and found the bolts and keeper assemblies for those valves intact.

The licensee worked with the valve manufacturer to redesign the bolt keeper assembly. The lock wire arrangement was replaced with a tabbed locking plate and locking tab to prevent the bolt from turning. The new design increased the anti-rotation capability of the keeper assembly by 7 times over the old design.

The new keeper design was installed in the discharge check valves for all three feedwater pumps. The licensee completed a loose parts evaluation for a beville washer and flat locking bar that was not retrieved from valve FW-2A assembly and concluded that the loose parts are trapped in the feedwater system and could not affect the reactor.

Inspector review of the scram sequence of events and the licensee's post-trip actions are summarized below. The licensee adequately identified the root cause for the trip and took actions to prevent recurrence. Approval to restart the reactor following repairs to the feedwater system was given by plant management at 10:30 p.m. on October 22. Inspector review of maintenance and testing activities to support plant restart is discussed further below. No inadequacies were identified.

3.6.2 Sequence of Events

The inspector reviewed control room panel indications, logs, and computer data, and interviewed operators to develop the following event sequence.

3:05 p.m.	Reactor Operator (RO) opens "B" Feedwater Regulating Valve (FRV) in manual and verifies "A" FRV responds in automatic.
3:20 p.m.	Feedwater discharge pressure and low flow alarms actuate followed in two seconds by flow fluctuations. Oncoming and offgoing shift operators respond to alarms.
3:12 p.m.	Operator shuts "B" FRV and notes reactor vessel level continues to increase.
3:14 p.m.	Operator shuts "B FRV block valve.
3:15:02.792	Reactor Vessel High Level Alarm
3:15:46.672	Main Turbine Trip
3:15:46.860	Reactor Scram on Turbine Stop Valve Closure
3:15:46.996	Turbine By-pass Valves Open
3:15:49.276	Reactor Vessel High Level Alarm Clear
3:15:57	Reactor Vessel Low Level Alarm (Vessel level shrink)
3:15:59.720	Manual Reactor Scram. Operators initiate Emergency Operating Procedures (ONP-502)

3:20 p.m. Operator identified "A" FRV is full open, when it should be shut.

3:25 p.m. Operator verifies no remote control of "A" FRV, closes the associated block valve. Operators complete ONP-502.

3:40 p.m. ENS call to the NRC Operation Center - Stabilized plant conditions.

The inspector reviewed the licensee's post trip review, scram report data sheet, the auto post trip review log, and the time history plots of plant parameters. The scram report data sheet documented initial plant conditions, cause of the scram and a brief description of events. The licensee's post trip review was accurate and complete and no discrepancies were identified. The inspector had no further questions in this area.

3.6.3 Findings and Assessment

The inspector observed the scram and post scram recovery actions taken by the licensee. The operators took the appropriate actions in an attempt to recover reactor vessel level prior to the scram. During the post scram recovery, actions were taken in accordance with the emergency operating procedures.

The inspector noted that since the scram occurred during shift turnover, up to eight operators were at the control board at the same time during the event. It was unclear to the inspector who was in charge since both oncoming and offgoing shift supervisors were providing directions. The decision to complete shift turnover was made at 4:45 p.m., 45 minutes after the plant had been stabilized. Although the operators properly responded to the transient and no inappropriate actions were taken as a result of the dual lines of authority, the inspector concluded there appeared to be a potential weakness in the command and control function.

The inspector also noted that some discussions by operations supervisory and management personnel regarding scram followup investigations and repair plans could have been conducted away from the main panels. Inspector observations and concerns were discussed in a meeting with the Unit Superintendent on October 20, 1989. No unsafe conditions resulted in this instance.

Licensee actions to investigate and correct the root cause for the feedwater regulating valve failure were thorough and effective to prevent recurrence of the trip. There was excellent engineering support provided to operations and maintenance to identify the cause of the feedwater malfunction, and to redesign the feedwater discharge check valve seat holddown bolt and keeper arrangement.

In summary, operators demonstrated good response to the transient, and good control and manipulation of plant systems following the trip. Control of post trip support activities could be improved. Followup evaluations and corrective actions for the cause of the transient were thorough and proper. No inadequacies were identified.

3.7 Plant Startup Activities - Unit 1

Plant restart following the Millstone 1 reactor scram commenced on October 22 following repairs to the feedwater regulating valve. The reactor was taken critical at 12:55 a.m. on October 23. Plant heatup was delayed on October 23 while gland seal regulator leakage was repaired to draw condenser vacuum. The reactor mode switch was placed in RUN at 9:15 a.m. on October 24 and the turbine generator was placed online at 11:12 a.m. Power ascension was held at 60% full power on October 24 to investigate and plug 4 tubes in the "C" condenser water box. Full power operation was attained at 11:16 a.m. on October 25.

The inspector reviewed activities by plant management and operators to support restart of the plant following the scram. Inspection included review of plant system status in the plant and from the control room, witness of operator actions for conformance with applicable procedures during the period of October 22-24, and review of surveillance testing for startup. No inadequacies were identified.

3.8 Review of Millstone 1 Emergency Operating Procedure Plant Specific Technical Deviations

Millstone 1 implemented emergency operating procedures (EOPs) on September 1, 1989 that were written to revision 4 of the Boiling Water Reactor emergency procedure guidelines (EPGs). An NRC Region I inspection of the EOPs completed on October 27 identified that the Millstone 1 plant specific technical guidelines (PSTGs) deviated from the EPGs, including four major deviations from the boiling water reactor EPGs approved by the NRC staff in a November 1988 safety evaluation. The Millstone 1 deviations are documented in a licensee letter to the staff dated October 19, 1989.

The deviations appeared to involve a significant change in accident mitigation philosophy in that assurance of core cooling is given a higher priority than the containment for certain scenarios. An example was the contingency for reactor vessel emergency depressurization. As a prerequisite to mitigation actions to protect the containment when degraded conditions exist, the Millstone 1 EOPs require that a reactor makeup source be available prior to depressurizing the reactor. This approach possibly could defer reactor depressurization while actions are taken to assure core cooling at a time when torus level was approaching or below the bottom of the downcomers. This strategy replaces the EPG emphasis to preserve the containment as a barrier at all costs, with one that risks containment integrity to assure core cooling. The basis for the deviation involved an attempt to optimize the use of the isolation condenser.

The NRC Region I EOP inspection results are documented in inspection report 50-245/89-19. This matter was referred to the NRC:NRR on November 7 for review to determine the acceptability of the Millstone 1 accident mitigation strategies as described in the October 19 deviation submittal. This matter is considered an unresolved item pending completion of the staff review (50-245/89-25-01).

3.9 Potentially Degraded Feedwater Coolant Injection (FWCI) System - Unit 1

The licensee notified the inspector on November 17 that the feedwater cooling injection system (FWCI) had been declared administratively inoperable as of 6:45 p.m. The action was taken in response to an operability evaluation by engineering which concluded that the air supply to the air-operated feedwater pump minimum flow valves lacked seismic qualification, such that the valves might fail open and thereby degrade FWCI system performance following a design basis earthquake.

The licensee reported that FWCI design flow of 8000 gallons per minute (gpm) could be degraded by up to 2800 gpm assuming all three minimum flow valves failed open. The plant at the time of identification was operating at 100% full power and the FWCI system was operating for normal feedwater make-up to the reactor. The FWCI function using either the "A" or "B" feedwater trains remained available.

The plant entered a seven day action statement per technical specification 3.5.C.3, which required the system be returned to a fully operable status by November 24, or the plant be taken to cold shutdown. The licensee completed a plant modification to install a seismically qualified backup air supply. The modifications were completed per design package 1-33-89 and are discussed further in Section 6.1.1 below. The backup system installation was completed on November 22 and tested satisfactorily using special test procedure 89-1-46. The licensee declared the FWCI system operable at 9:00 p.m. on November 22 and the plant exited the TS 3.5.C.3 limiting condition of operation.

The inspector reviewed licensee actions to meet technical specification 3.5.C.3 during the period FWCI was inoperable. This review verified that in addition to the selected and alternate FWCI trains remaining available to perform the normal feedwater function, the automatic pressure relief, isolation condenser, core spray and low pressure coolant injection systems remained operable. No inadequacies were identified.

The licensee stated this matter will be formally reported to the NRC as a licensee event report. The licensee stated the safety significance of plant operation while the air supply to the minimum flow valves was not seismically qualified was low, in that engineering analyses show that the FWCI system is not needed to mitigate the design basis accidents. This matter will be reviewed further as part of routine resident inspection of the licensee event report (LER). This item is considered unresolved pending NRC review of: the impact of loss of air on FWCI operability; the significance of the event on plant operations and meeting license requirements; and, licensee reporting of the issue, including issuance of the LER (50-245/89-25-02).

3.10 "A" Recirculation Pump Motor - Generator Speed Control Failure - Unit 1

3.10.1 Event Summary

At 2:30 p.m., on November 26, 1989, with the reactor at 100% of rated power, a failure of the "A" recirculation pump motor-generator (MG) speed controller caused the pump to run back to minimum speed (28%) and a consequent reactor power decrease to 76%. As a result of the flow mismatch between the recirculation loops, the licensee entered technical specification limiting conditions for operation 3.6.H.1, regarding recirculation pump flow mismatch. Within 15 minutes, operators had taken local - manual control of the MG and had begun to restore recirculation flow and reactor power under the direction of the reactor engineer. By 3:35 p.m., recirculation loop flows were within technical specification limits, and reactor power was restored to 100% at 4:00 p.m.

3.10.2 Post-Event Licensee Response

The inspector observed licensee recovery operations in the control room and trouble-shooting efforts at the MG speed controller. Operators responded to the event professionally and appropriately in accordance with procedures ONP-504, Recirculation System Failures, Revision 3 (dated March 29, 1989), and OP-301, Nuclear Steam Supply System (RR System), Revision 28, change 1 (dated November 15, 1989).

Troubleshooting on the speed controller and its inputs commenced almost immediately. The cause of the controller failure could not be determined, however. Based on equipment failure history, it was decided to replace those relays, failure of which could result in a similar runback; i.e. those associated with pump discharge isolation valve position and feedwater system flow. A recorder was installed to monitor the performance of these relays. Finally, as a precaution, the corresponding relays in the "B" recirculation pump MG speed controller were replaced.

The inspector observed the troubleshooting at the scene and found licensee personnel to be knowledgeable of system operation and equipment maintenance history. Activities were logical and thorough, and current technical materials were used.

3.10.3 Safety Significance

Technical specification (TS) 3.6.H.1 requires that whenever both recirculation pumps are in operation, pump speeds must be within 10% of each other when reactor power is greater than 80% and within 15% of each other when reactor power is less than 80%. Step 3.6.H.2 states that if these flow conditions cannot be met, one recirculation pump shall be tripped. Operation with a single recirculation loop is permitted by Millstone 1 technical specifications for 24 hours. The limits are based upon the ability of the low pressure coolant injection (LPCI) loop selection logic system to select an undamaged core injection path in the event of a loss of coolant accident. Inputs to the logic circuit are recirculation pump and jet pump riser manifold differential pressure. The Millstone 1 Updated Final Safety Analysis Report, section 6.2.4.2, states that the core spray system alone is sufficient to maintain fuel temperature within acceptable values in the event of a postulated accident.

The licensee interprets technical specification 3.6.H.2 to require entry into single loop operation if recovery of the affected loop cannot be achieved within a reasonable time; i.e. initial flow conditions "cannot be met". Under the conditions of core power and total core flow prevailing after the runback, tripping the affected recirculation pump would result in reactor operation closer to a region of potential core thermal-hydraulic instability. The inspector agreed that in cases where loop flow could be restored expeditiously, the more conservative action was to do so, rather than trip the pump. Due to the ambiguity of the technical specification, the licensee committed to submit a proposed amendment specifying an allowable loop flow recovery time. The inspector had no further questions.

3.11 Summary

Millstone 1

Excellent engineering support to operations and maintenance to identify the cause of the feedwater malfunction and re-design of the feedwater check valves was a notable strength. Generally, good operator response was noted to the reactor scram; however, post-scram support activities could be improved to not detract from command and control during plant transients.

Two unresolved items were identified: One, (89-25-01), involves further NRC review to determine acceptability of accident mitigation strat .es as documented in the licensee's October 19 deviation submittal. The other (89-25-02) involves NRC review of FWCI operability on loss of air and licensee reporting of the issue.

Millstone 2

Inter-departmental cooperation was exemplary and health physics support for the outage was assessed as good. Problem identification and control of plant activities during the Unusual Event was assessed as good.

4.0 Radiological Controls (IP 71707/92701)

4.1 Posting and Control of Radiological Areas

During plant tours, posting of contaminated, high airborne radiation, and high radiation areas were reviewed with respect to boundary identification, locking requirements, and appropriate control points. No inadequacies were noted.

4.2 LER 50-245/89-20 Followup - Contaminated Materials Outside RCA - Unit 1

The licensee submitted this information LER by letter dated November 6 to describe the actions in response to the discovery of contaminated tools in an offsite warehouse on Great Neck Road in Waterford, Connecticut. NRC inspection of the technical and regulatory aspects of the event are described in Inspection Report 50-245/89-23.

LER 89-20 was reviewed and found to accurately describe the event and the licensee's corrective actions. The licensee determined the root cause for the loss of control of slightly contaminated materials was a failure to perform adequate surveys of materials exiting the radiological controlled area (RCA), and a failure to establish adequate procedures to prevent the inadvertent spread of contamination. NRC followup of this item and subsequent licensee corrective actions to prevent recurrence is tracked by Inspection Item 50-245/89-23-02.

The licensee completed a contamination survey at another Northeast Utilities facility (Devon Station) where a large inventory of tools are kept. The licensee reported that the surveys were complete as of November 17 and the results showed no contamination of the plant or tool storage areas. The licensee completed a piece-wise survey of about 5000 tools at the station, which exceeded the 3500 that were on the inventory list of items that may have been distributed from the Great Neck Road warehouse. All tools surveyed were found free of contamination, except for one 9-inch crescent wrench. The wrench had fixed Cesium-137 contamination at levels of 300 corrected counts per minute (ccpm) above background on contact, and less than 100 ccpm when surveyed at 1/2 inch using a standard frisker. The wrench was returned to Millstone.

A licensee task force is scheduled to complete its review and make further recommendations to prevent recurrence of the problem by December 30, 1989. The control and release of material from radiologically controlled areas will be reviewed further on subsequent routine NRC inspections. The inspector had no further questions at this time. No inadequacies were identified relative to event reporting.

4.3 <u>Personnel Contamination Monitor Alarms During The Mid-Cycle Outage - Unit 2</u>

On October 27, the inspector was contacted by a contractor employee who had the following concern: when fellow workers exited the containment for the initial decontamination efforts and the removal of the primary steam generator manways, they alarmed the personnel contamination monitors (PCM-1B) in the auxiliary building. The individual was concerned about the potential health effects.

The inspector discussed the contractor's concern with utility health physics management. The licensee indicated that two events in the early stages of the outage contributed high containment airborne gaseous activity. The two occasions were the initial decontamination of containment, and on October 25, during removal of the No. 2 steam generator manway a partial disconnection in the ventilation flow occurred. Containment airborne samples indicated no particulate or iodine activities, however, a relatively large concentration of noble gas activity (i.e. 1.5 X 10-1 microcuries/milliliter) was identified. The health physics actions to reduce the noble gas were application of a nitrogen purge on the pressurizer, containment venting, and random airborne samples.

The inspector reviewed the sensitivity of the PCM-1B personnel contamination monitors. The detectability of the monitors are 5000 dpm/100cm2 for a two-inch diameter location; and low levels of distributed contamination (i.e. <1000 dpm/100cm2) over the entire body. During the early part of the outage, licensee management decided to let contractor force personnel leave the site after alarming the PCM-1B, based on: personnel contamination surveys with an HP-210 detector revealing less than 1000dpm/100cm2; showers of select individuals to determine if contamination is inhaled and deposited internally; and assurance that the workers revisit the PCM-1B monitors the following day, and the subsequent results were less than the alarm setpoint.

The licensee provided a plant distribution memo (MP-S-5244) on November 3, to identify the health physics actions, and address health concerns regarding personnel contamination monitor alarms. The inspector called the concerned individual, based on the investigation results. The individual had no further questions and was satisfied. This item is closed.

4.4 Summary

Licensee review of the root cause determination for LER 89-20 was sufficient with extensive followup.

Sufficient control of personnel monitoring during the Unit 2 outage was noted.

5.0 Maintenance/Surveillance (IP 62703/61726/92702)

5.1 Observation of Maintenance Activities - Units 1 and 2

Maintenance activities were reviewed to determine the scope and nature of work done on safety related equipment and to verify the activities were completed in accordance with established procedures and plant equipment controls. Proper implementation of safety related tagging was also verified during inspector review of maintenance activities. Tagging associated with switching orders 1-2098-89, 1-2101-89 2-2886-89, 2-2877-89, 2-2880-89, and 2-2951-89, and by-pass jumper evaluations 89-67, 89-68, 89-69, 89-70, 89-74 and 89-75 were reviewed and found acceptable.

Maintenance and testing activities associated with the following were reviewed to verify (where applicable) procedure compliance and proper return to service, including operability testing.

-- AWO M1-89-11733, "A" FRV Failed Open
-- AWO M1-89-11757, "B" FRV Packing Leak
-- AWO M1-89-11744, "A" Feedwater Pump Discharge Check Valve
-- AWO M1-89-12732, "B" FRV Minimum Flow Valve Air Supply
-- AWO M1-89-12722, "A" FRV Minimum Flow Valve Air Supply
-- AWO M1-89-12723, "C" FRV Minimum Flow Valve Air Supply
-- AWO M1-88-10381, Perform IC-414A, CRD Module Instrument Calibration
-- AWO M1-88-06342, PDCR 1-74-86: Extend Existing LLRT Connections on Electrical Penetrations
-- AWO M1-89-12936, "A" Recirculating Pump MG Set Speed Controller Not Functioning Properly
-- AWO M1-89-12948, Replace K103B and K104B Relays - "B" Recirculating Pump MG Set Speed Control
-- AWO M1-89-10179, Repair Breaker for 1-MS-6 at MCC-101-AB-2
-- AWO M1-89-11246, "B" Fuel Pool Heat Exchanger Tube Leak
-- AWO M1-89-11983, IRM 16 Voltage Pre-Amplifier
-- AWO M1-89-12444, "A" FRV Failed Open
-- AWO M1-89-12607, Emergency Diesel Generator - Inspect Right Side Fuel Control Rod per SIL-A-22
-- PDCR 1-89-32, Feedwater Discharge Check Valve Seat Retaining Assembly Modification
-- PDCR 1-89-33, FRV Minimum Flow Seismic Backup Air Supply
-- AWO M2-89-11543, Pressurizer Heater Inspection
-- AWO M2-89-06672, Auxiliary Feedwater Check Valve Repair
-- AWO M2-88-11232, Vital Inverter Capacitor Replacement
-- AWO M2-89-12229, Service Water Strainer Support Installation
-- AWO M2-89-13005, Valve 2-FW-12A Electrical Equipment Qualification Walkdown
-- AWO M2-89-11824, Repair of 2-FW-4B
-- AWO M2-89-11825, Repair of 2-FW-4A

No inadequacies were identified. The items below were selected for additional inspector followup.

5.1.1 AWO M1-89-11744, "A" Feedwater Pump Discharge Check Valve Failure on October 19, 1989

The "A" feedwater regulating valve (FRV) was removed following draining and cooldown of the header. A 7/8 inch bolt was found under the "A" FRV seat. The licensee determined that the bolt came from the "A" feedwater pump discharge check valve FW-2A. Licensee inspection per AWO 89-11733 identified no major damage to the "A" FRV; there was minor scoring on the cage and on the hemispherical head of the FRV. The damage did not affect either seating surface on the dual seat Copes Vulcan valve. Licensee corrective action was to lap the FRV seats and re-assemble the valve. The valve was subsequently stroke tested satisfactorily.

Feedwater check valve 1-FW-2A is manufactured by the Crane-Chapman Company and is a Model 1573 pressure seal tilting disc valve. The check valve normally has two valve seat hold-down bolts with a lock wire keeper assembly. Licensee inspection per AWO 89-11744 found one of the two bolts missing from the 2A valve and the second bolt along with its keeper assembly was loose. The licensee inspected the discharge check valves for the B&C feedwater pumps and found the bolts and keeper assemblies for those valves intact. Following review of feedwater check valve design and failure history, the licensee redesigned the valve hold down assembly per PDCR 1-32-89. The details of that modification are discussed further in Section 6.1 below.

The licensee completed a loose parts evaluation on October 22 for a bevel washer and flat locking bar that was not retrieved from valve FW-2A and concluded the loose parts are trapped in the feedwater system and could not affect the reactor. This matter is discussed further in Section 5.1.2 below.

No inadequacies were identified regarding the repairs for the "A" feedwater regulating valve and the "A" feedwater pump discharge check valve. NRC concerns regarding the licensee's program to address check valves at Millstone 1 per SOER 86-03 are addressed further in Section 5.3 below.

5.1.2 AWO M1-89-12444, "A" FRV Failure on November 9, 1989 - Unit 1

On November 9, when power was reduced to 80% for routine turbine stop valve testing, the "A" feedwater regulating valve stuck in the open position at 5:25 a.m. Plant operators noted that with both individual and master feedwater control stations in automatic, the "B" FRV was at 24% open while the "A" FRV was at about 50% open. Subsequent investigation determined that the "A" FRV was mechanically stuck. The corresponding manual isolation valve was closed at 5:48 a.m. pending completion of repairs. The plant was held at 70% power while the valve was opened and inspected per AWO 89-12444.

Licensee inspections in the afternoon of November 9 found a loose part in the bottom seat area of the FRV. The part was the missing old-type feedwater check valve locking plate, which was retrieved. Licensee inspection found no damage to the seat or cage of the FRV and the valve was re-assembled.

The inspector met with licensee management on November 9 and requested the licensee to address: (i) the source of the loose part; (ii) what other loose parts might still be in the system; and, (iii) what assurance the licensee had that any remaining loose parts in the feedwater system would not adversely affect FWCI operation. The licensee re-reviewed the bases for the loose parts evaluation for 1-FW-2A completed following the "A" FRV failure on October 19; researched work order records from previous known failures of the feedwater check valves; and, performed a demonstration in the maintenance shop using a spare FRV plug and cage assembly to evaluate possible failure modes.

Licensee investigation of work order M1-84-05449 determined that following the failure of the "C" feedwater check valve on December 5, 1989, the seat retaining bolt was retrieved from the "A" FRV seat area, along with the other missing parts from the check valve seat assembly. These parts included the locking plate with stud and the lockwire. The bolt was still attached to the locking plate. The part not retrieved was the associated washer. Following the "A" FRV failure on October 19, 1989, the seat retaining bolt was retrieved, but not the bevel washer or the locking plate. The licensee's initial conclusion on October 22 was that the locking plate and bevel washer from the "A" feedwater check valve had passed through the FRV area in the feedwater system and were trapped in the inlet water box of the high intermediate pressure (HIP) feedwater heater. Since the outside diameter of the feedwater heater tubes is 5/8 inches, none of the valve loose parts (washer - 2" diameter; locking bar - 2.5" X 1.75") could travel any further in the system to reach the reactor. The licensee concluded that the locking plate retrieved from the "A" FRV on November 9 was the part missing from the "A" feedwater check valve on October 19.

Based on the above, the only known missing valve parts still in the feedwater system were two 2" diameter bevel washers.

The licensee concluded that both washers most likely had passed through the FRV station and were now in the HIP area. Assuming the washers were still trapped upstream of the FRVs, the licensee was able to demonstrate to the inspector that the parts would most likely pass through the FRV, and that if it did "stick" in the FRV, the only possible failure mode would be to hold the valve in the "open" position. Thus, the FWCI function could not be compromised. The inspector verified further using the valve mockup in the maintenance shop that the locking bar, when lost in the system from October 19 to November 9, could not have failed the FRVs in the "closed" position. This conclusion was based on a measurement which showed the full stroke on the FRV is 2 -3/8 inches in the full open position, which is smaller than the minimum dimension of the locking bar retrieved from the system on November 9.

Based on the above, even though the licensee's October 22 loose parts evaluation for the 1-FW-2A feedwater check valve was subsequently proven inaccurate regarding the location of the missing parts, no unsafe conditions occurred. The inspector identified no inadequacies in the licensee's actions or plans to continue plant operation at power.

Following completion of repairs and testing, the "A" FRV was placed back in service at 9:06 p.m. on November 9. The valve subsequently operated satisfactorily in automatic control at 9:17 p.m. and power ascension was resumed. The plant attained full power operation at 11:45 p.m.

5.1.3 Failure of Auxiliary Feedwater Turbine Steam Supply Check Valve - Unit 2

On November 1, the licensee notified the inspector of the results of its inspection of the four-inch swing check valve 2-MS-4B, which is the steam supply from the No. 2 steam generator to the turbine-driven auxiliary feedwater pump. The valve was being disassembled as a result of an in-service test (SP-21135) surveillance failure on June 22, 1989.

Northeast Utilities inspection of 2-MS-4B revealed the disc pin and nut were gone and the disc was separated from the hinge arm. The disc was located on the bottom of the valve body. The initial corrective actions included boroscopic checks to locate the disc pin and nut in the steam system, and modification alternatives with the valve manufacturer (Anchor/Darling).

The licensee located the two internal check valve parts in a steam trap just prior to the terry turbine stop valve (SV-4188). The disc pin was smooth, concave and the length was shortened, and the disc nut had no apparent damage. The licensee engineering staff recommended to the vendor to tack weld the disc pin to the nut. The vendor accepted the licensee's proposed repair, and stated no adverse effects on the valve operability exist. Electric Power Research Institute (EPRI) "Application for Guidelines for Check Valves in Nuclear Power Plants" guide 2.5.7 indicates "...welding can be an effective locking method for threaded fasteners, pins, and other devices; however, the weld must be designed and controlled. The inspector reviewed the corporate engineering welding procedure and evaluations for the weld and found it acceptable as it relates to material compatibility and stresses. Plant design change request (PDCR) 2-89-115 documented the method and justification for the tack weld for the disc pin to nut on 2-FW-4B.

The inspector reviewed work orders M2-89-11824 and M2-89-11825 to implement PDCR 2-89-115 for both valve 2-FW-4B and its counterpart for the No. 1 steam generator, valve 2-FW-4A.

The operability of the auxiliary feedwater system as it related to the failure of 2-FW-4B in-service test, and licensee isolation of one of the parallel steam supplies to the turbine-driven auxiliary feedwater pumps was reviewed in routine inspection report 50-336/89-22. The review considered the recent NRC information notice 89-58 dated August 3, 1989. In conclusion, the licensee maintained the auxiliary feedwater intended safety function with one of two parallel steam supply valves shut to the turbine driven auxiliary feedwater pump.

The inspector reviewed the history of 2-FW-4B corrective maintenance. In March, 1988, this valve was replaced with a new internally counter-weighted valve During the time frame of April - July 1988, the internal counter-weight was adjusted three times to minimize valve chattering during operation. In June, 1989 the valve failed its reverse-flow inservice test. The utility is considering a long-term replacement of the check valve with an external counter balancing weight.

In conclusion, the performance of swing check valve 2-FW-4B has developed repetitive valve "chatter" that requires readjustments and replacements. Licensee re-evaluation of this valve has not adequately addressed the "root cause" for the valve degradation, based upon previous failures of the same valve and the ongoing valve chattering problem. NRC routine inspection will follow future licensee actions.

5.2 <u>Observation of Surveillance Activities - Units 1 and 2</u>

The surveillance test results listed below were reviewed to verify that testing was performed in accordance with approved procedures, test results demonstrated compliance with technical specification and administrative requirements, and that deficiencies (if any) were corrected in accordance with established administrative requirements.

-- SP 668.2, Gas Turbine Emergency Fast Start Test, Revision 11
-- SP 406E, Air Ejector Off Gas Isolation Radiation Monitor Functional Test, Rev. 6

- -- SP 668.1, Diesel Generator Operational Readiness Demonstration, Rev. 14
- -- SP 623.9, Check When One of the Valves in the System Isolating the Containment is Inoperable, Rev. 5
- -- SP 621.10, Core Spray System Operability Test, Rev. 5
- -- IC 414A, Control Rod Drive Module Instrument Calibration, Rev. 6
- -- IC 412G, Break Detection Valve Permissive Functional And Calibration Test, Rev. 10, Change 1
- -- IC 419C, FRV Station Functional Check, Rev. 1
- -- SP 608.13, Condensate and Feedwater System Pump Discharge Check Valve Readiness Test, Rev. 7 completed
- -- SP 608.33, Cold Shutdown Testing of Master Solenoids and Scram Discharge Volume Vent & Drain Valves
- -- SP 1049, Rod Worth Minimizer Verification for Control Rod Sequence, Rev. 4
- -- OPS Form 608.30-1, Cold Shutdown/Refuel Power Operated Valve Readiness Test, Rev. 6
- -- OPS Form 201-1, Pre-Critical Checkoff List, Rev. 11
- -- OP 220-1, Drywell Closeout Inspection, Rev. 0
- -- OPS Form 10.10, Shift Surveillance
- -- OPS Form 201-2, CRP 905 Pre-Critical Checklist, Rev. 6
- -- SP 624.1, Secondary Containment Tightness Test, Rev. 6
- -- Special Test Procedure 89-1-45, Secondary Containment Tightness Test, Rev. 0
- -- IC 419C, Feedwater Regulating Valve Station Functional Check, Rev. 1
- -- SP 89-1-46, FWCI Air to Minimum Flow Valve Test, Rev. 0
- -- OP-2605A-1, Containment Penetration Verification
- -- PT-1405, Hi-Pot ±A' Reactor Coolant Pump
- -- SP-2801I, Local Power Density Functional
- -- OP-2201, Plant Heat-up
- -- SP-2602C, Reactor Coolant System Hydrostatic Test
- -- SP-2609C, Enclosure Building Integrity Verification
- -- SP-2619D, Start-up Checklist

No inadequacies were identified, except as noted below.

5.2.1 Secondary Containment Tightness Test - Unit 1

The inspector was informed on October 17 of a problem identified at another facility regarding an inadequate test method for demonstrating the leak tightness of the secondary containment. The deficiency involved the operation for the plant main exhaust (PME) fans concurrently with the running of the standby gas treatment system (SGTS). The effect of the deficient test method was that the operating PME fans masked degradation and gross leakage in reactor building (RB) vent system. Inspector review of licensee procedure SP 624.1 noted that the test method was similar to the other facility. Further inspector review of the reactor building ventilation system configuration identified a similar configuration indicating Millstone 1 could be susceptible to the problem. However, unlike that other facility which used ventilation ducting and isolation dampers, the vent system at Millstone 1 uses hard piping and butterfly valves from the reactor building wall out to the building isolation boundary just prior to the connection to the plant main exhaust system, which is a significant difference. The matter was referred to the licensee for review.

The licensee wrote a new test procedure, SP 89-1-45, and performed a test of the secondary containment tightness on October 21, 1989. SP 89-1-45 modified the test method used in SP 624.1 to verify that each SGTS filter train could maintain a 1/4 inch water vacuum on the reactor building with the PME fans secured. The inspector reviewed the test data completed for the "A" SGTS filter train and noted the results were acceptable. The licensee proved the SGTS was operable and that secondary containment integrity met the technical specification requirements. The inspector had no further questions on this matter. No inadequacies were identified.

5.2.2 Local Power Range Monitor (LPRM) Spiking - Unit 1

From August to December, 1989, the licensee has recorded over 70 spiking events on the LPRMs. On five occasions, reactor protection system half-scram actuations have occurred on their associated average power range monitors (APRMs). In each case, the spikes were of short duration and the half-scrams were reset immediately.

The LPRMs involved are model NA-300, supplied by the Reuter-Stokes division of General Electric Company (GE). The detectors are small fission chambers with an inner coating of enriched uranium dioxide and are operated at 100 volts direct current (vdc). At Millstone 1, 24 LPRM detectors have exhibited spiking periodically. The manufacturer attributes the phenomenon either to growth and subsequent release of metallic uranium "whiskers" or the presence of loose microscopic fragments on the coating. The problem appears to be limited to those detectors fabricated during a specific period in 1986 and not generic to model NA-300. GE has recommended that licensees perform monthly current-voltage (I/V) tests on the LPRMs, raising detector voltage to greater than 200 vdc.

The licensee performs weekly I/V tests on the LPRMs in accordance with procedure SP-88-1-1, Revision 0, dated March 2, 1988. Voltage is raised to 250 vdc and an I/V curve produced on which spikes, if any, are recorded. In late November 1989, personnel from Reuter-Stokes and licensee instrumentation and controls technicians performed special test 89-1-47, Rev. 0, dated November 28, 1989. Using a computer and digital storage oscilloscope, detector voltage was automatically ramped-up and current recorded for further analysis. On November 29, the inspector witnessed the performance of the special test and observed the occurrence of spikes on several LPRMs.

As a long term solution, a filter circuit has been designed by GE on the LPRM instrument first-stage amplifier. Eight instrument cards have been modified and await licensee seismic evaluation. The licensee plans to install these modified cards in the LPRM groups not associated with the reactor protection system for evaluation prior to use in the instruments associated with the APRMs.

The inspector witnessed the bypassing of several affected LPRM channels in accordance with procedure IC403A, Nuclear Instrumentation (LPRM Channels), Rev. 3, dated October 25, 1989, and verified operator compliance with technical specifications table 3.1.1, Reactor Protection System (Scram) Instrumentation, requirements regarding the minimum number of LPRM inputs necessary for APRM operability. Licensee actions were considered by the inspector to be appropriate. Final resolution of this issue will be followed during future routine inspections.

5.3 ITT Grinnell Snubber 10 CFR 21 Report - Unit 2

On July 13, 1989, another utility submitted to the NRC a 10 CFR 21 report regarding a failure of a tie rod nut for the Grinnell Snubber 10" X 5" Tomkins-Johnson (TJ) piston/cylinder assembly. The snubber application was for the steam generators. The tie rods hold the snubber piston and cylinder assembly together in the axial direction.

In the event documented in the 10 CFR 21 report, the tie rod nut report sheered in half during the final torquing pass of the tie rods. The reporting utility conducted an investigation into the failure and concluded it was a result of substandard material properties and questionable dimensional tolerance of the tie rod nut. Specifically, the material properties of the tie rod nut specification should have been AISI 4140 alloy, however, the tested nuts were AISI 1140 alloy. The differences in the alloy material is the AISI 1140 has less tensile and yield strength. The utility concluded, further, that the nuts were inferior in strength, increasing the probability of failure under actual design loading conditions.

On July 27, Northeast Utilities determined the applicability of the Grinnell 10" X 5" TJ snubbers (early 1970 version) at the Millstone Station and Connecticut Yankee. Millstone 2 has the susceptible hydraulic snubbers. The licensee identified a total of sixteen Grinnell TJ snubbers all for both steam generators. On October 18, the licensee sent a letter to the vendor (Grinnell Corporation) to identify the potential impact of the tie rod nut material, and to assess the operability of the hydraulic steam generator snubbers.

On November 6, the licensee completed chemical composition, hardness, and dimensional accuracy evaluations for two flange nuts on a spare TJ (1970 version) steam generator snubber. The results of the chemical analysis indicated that the nut was nominally an AISI 4140 alloy. The average rockwell hardness of 34.7 was measured. The hardness corresponded to a tensile strength of approximately 150,000 psi. The inspector verified the manufacturing specifications, chemistry specification, and mechanical properties of the tested nuts were in agreement with the vendors specifications. All properties were within the tolerance values. The dimensional analysis was in agreement with the vendor's specifications.

The steam generator snubbers were rebuilt during the 1986 refueling outage. The licensee reported that no visual indication of inferior tie rod nuts were noted at the time.

The licensee is considering further actions in regards to this 10 CFR 21 report including; replacement of the tie rod nuts with the vendor recommended replacements, and further examination of installed steam generator snubbers. Licensee actions will be reviewed as part of routine inspection follow-up.

5.4 Reactor Coolant System Cold Leg Temperature Response Time Test Failure - Unit 2

On November 20, 1989, the licensee documented a response time failure of resistance temperature detector (RTD) 112CC, which is one of two reactor coolant system (RCS) cold leg temperature inputs to channel "C" of the reactor protection system. The cold leg temperature inputs to the local power density, variable high power, and thermal margin low pressure reactor trips. The response time is defined as less than or equal to eight seconds, per technical specification table 3.3-2. The response time requirement is the time interval required for the RTD's output to achieve 63.2% of the total change when subjected to a step change temperature input. Surveillance requirement 4.3.1.1.4 requires the response time of all reactor trip system RTDs to be verified within one month of operation for newly installed RTDs and every eighteen months thereafter. RTD 112CC was installed in early November, 1989.

Surveillance procedure (SP) 2401Q verifies the response time of the RCS RTDs. The failed RTDs response ranged between 14-20 seconds.

On November 21, the utility documented an operability evaluation for the RCS RTD. Referenced in the operability statement were two previous engineering analyses to identify the minimum RTD operability requirements for reactor protection system operability consistent with the accident analysis.

Plant analyzed transients which require reactor protection trips using cold leg temperature as an input are: control element assembly withdrawal, boron dilution, excess load, loss of load, loss of feedwater, excess feedwater, and reactor coolant system depressurization. Inclusion of the cold leg temperature in the trips is necessary when nuclear power becomes decalibrated. Decalibration is the difference in reactor power indication between nuclear instrumentation and reactor delta temperature. Decalibration of nuclear power occurs when the reactor coolant temperature changes, or upon movement of control element assemblies. The aforementioned transients are symmetric in the sense that all four cold legs and both hot legs behave the same. The utility concluded that as long as at least one cold leg temperature input and one hot leg temperature input are available, the reactor protection system will function consistent with the assumptions of the safety analysis. The most limiting asymmetric transient requiring reactor protection system response is the loss of load to one steam generator. The loss of load transient assumes trip functions independent of RTD input (i.e. low steam generator level or pressure trip).

The failure mode of the RTD is either low or high. If the RTD fails low, a control room computer alarm is generated, and if the RTD fails high, a channel "C" RPS trip on thermal margin low pressure, variable high power, and local power density results.

The operability evaluation for the reactor protection system was approved by the Plant Operations Review Committee during meeting 2-89-194 on November 21. The licensee considers the RTD inoperable based on the required unsuccessful response time, and has committed to replace the slow RTD during the next refueling outage presently scheduled in the fourth quarter in 1990.

Licensee followup actions include: (1) a caution tag for RTD 112CC to alert control room operators of the slow response time; (2) a copy of the operability evaluation in the unit's night order log; and, (3) additional channel check every eight hours included in daily technical specification check procedure SP-2619A.

The inspector reviewed the licensee's operability evaluation, night order log, procedural change to SP-2619A, surveillance procedure SP 2401Q, technical specification basis for reactor protection system trips, and the Final Safety Analysis Report. The inspector will track the licensee's commitment on resolution of RCS RTD 112CC in future inspections, and developed no further questions on the RTD operability.

5.5 Previously Identified Item

5.5.1 (Closed) Unresolved Item 50-245/87-21-02: Follow-up Actions from NRC Regional Administrator Tour on August 19, 1987

While touring Millstone 1 on August 19, 1987, the NRC Regional Administrator noted that the emergency diesel generator (EDG) fuel racks were not fully closed. In addition, the EDG governor droop setting was at 50% vice zero.

The licensee responded by stating that after the shutdown solenoid de-energizes, residual oil pressure in the governor causes the fuel rack to drift to a setting of approximately "1". Further, a restoration step in surveillance procedure SP 668.1, Diesel Generator Operational Readiness Demonstration, Revision 14, dated October 5, 1989, requires the operator to ensure that the fuel rack is not in the "0" or "no fuel" position after air rolling the EDG. This condition ensures that the shutdown solenoid is not stuck and that the fuel rack is free to move.

The Millstone 1 EDG utilizes a Woodward UG-8 governor. There is no circuit which automatically adjusts the speed droop as the machine is loaded. Consequently, leaving the speed droop set at 50% results in a frequency decrease of approximately three Hertz (Hz) when the engine is at full fuel (110% power) level. The licensee relies upon the operator to adjust engine speed as the EDG is loaded during a loss of normal power event.

The licensee initially determined that operation of emergency loads at 57 Hz was acceptable with the possible exception of the low pressure emergency core cooling systems. That is, the low pressure coolant injection (LPCI) and core spray (CS) systems might not achieve the required accident flow rates without operator manipulation of the EDG speed control. The licensee subsequently completed calculation W1-517-836-RE, Millstone 1: Acceptability of LPCI and CS Flow with Diesel Generator 5% [50% governor setting] Droop and Instrument Uncertainty, in March 1988. Minimum acceptable pump performance was determined by adjusting the minimum required post-accident system flow for instrument uncertainties and a calculated diesel speed droop penalty, and ensuring that the acceptance criteria of surveillance procedures SP 621.10, Core Spray System Operability

Test, and SP 622.7, LPCI System Operability Test, satisfied these requirements. Baseline flow values were derived from General Electric Company (GE) study EA S-02-0188k, Evaluation of the Minimum Required LPCI and Core Spray Flow for Millstone Point Nuclear Power Station Unit 1, dated January 1988.

-- Core Spray System: The minimum flow required by the CS system was determined by the GE study to be 3600 gallons per minute (gpm) at 90 psig in the reactor vessel. Surveillance procedure 621.10 demonstrates system operability by finding pump differential pressure at 3600 gpm to be equal to or greater than 261 psid. Adjusting for line losses, reactor vessel pressure, loss of pump head due to diesel generator droop, and instrument uncertainty, the minimum required pump discharge pressure was calcualted to be 126.25 + 90 + 31 + 13.1 = 260.35 psig. Thus, a measured differential pressure of 261 psid will satisfy the minimum flow requirement.

-- Low Pressure Coolant Injection System: Based on the GE study, the minimum required flow for one LPCI pump is approximately 4370 gpm at 20 psig in the reactor vessel. The minimum acceptable value specified in SP 622.7 is 5000 gpm at 80 psig pump discharge pressure. Adjusting for droop penalty, instrument uncertainty, operation with minimum flow valves open (see detail 6.6.2), and pump operating point, the minimum acceptable flow was found to be unsatisfactory using installed system instruments: 4370 + 359 + 752 + 71 - 83 = 5469 gpm at 80 psig pump discharge pressure. However, using a more accurate narrow range flow instrument (uncertainty = 142 gpm), the minimum acceptable flow was determined to be 4370 + 359 + 142 + 71 - 83 = 4859 gpm. Thus, a margin of 141 gpm exists between the value specified in the GE study and the acceptance criteria of the surveillance procedure.

The licensee performed special test 87-1-40, MP1 LPCI Flow Verification, using more accurate instruments and found that the pumps delivered approxmiately 5277 gpm at the required discharge pressure. This was well above the calculated minimum acceptable value.

In conclusion, successful completion of the existing CS system surveillance procedure will prove adequate post-accident flow at 57 Hz with very little margin to the GE study values. Determination of adequate LPCI flow requires use of instrumentation more accurate than that installed. Therefore, the licensee developed procedure SP 622.10, LPCI System Narrow Range Flow Verificationm, which calculates system flow with instruments of the required accuracy. The test is performed concurrently with SP 622.7, LPCI System Operability Test. Through review of the licensee calculations and surveillance procedure results, the inspector was satisfied that the low pressure emergency core cooling systems at Millstone 1 will deliver the required post-accident flows to the reactor vessel with the existing EDG governor speed droop setting. This item is closed.

5.6 Summary

The license's [illegible] parts evaluation for the 1-FW-2A feedwater check valve was subsequently proven inaccurate on October 22, however, no unsafe conditions occurred.

A detailed and acceptable evaluation on the failed RCS RTD as it related to RPS operability was noted.

Further consideration or evaluation is needed to increase confidence factors for Grinnell snubbers in reference to the 10 CFR 21 report.

The need for further utility enhancement of check valve performance is reinforced in report details 5.1.1, 5.1.3, and 3.6.

6.0 Engineering/Technical Support (IP 37700/37828/92702)

6.1 Backup Air to Feed Pump Minimum Flow Valves - Unit 1

The licensee implemented changes to the instrument air supply per plant design change record (PDCR) 1-33-89 to install a redundant air supply to the main reactor feedwater pump minimum flow valves, 1-FW-14A, 14B & 14C. The design changes were completed on November 22 and included the installation of high pressure air bottles, air pressure regulators, relief valves, check valves and necessary tubing.

The normal air supply to the valves was removed at the minimum flow valves and the supply tubing was abandoned in place. The old tubing was replaced by a common air header to each valve. The common header is in turn supplied from either the instrument air (IA) system or the newly installed high pressure air bottles. The air pressure regulator for the new high pressure bottles was set to a lower pressure than the normal air supply, so that the IA system remained the primary source to the minimum flow valve air operators. Check valves installed in the air lines assure delivery of air to the minimum flow valves in the event of the loss of the normal air system.

The size of the air supply lines was increased from three-eighth to one-half inch to assure the air supply capacity from the common header to the three valves remains adequate. The new air supply system was installed as a seismic Category 1 system. The pressure relief valves were also seismically qualified, as demonstrated by a special seismic performance test conducted on

November 22 by Ontario Hydro Research Laboratories. The seismic spectrum for the test enveloped both the 14 foot/6 inch and the 34-foot elevations of the Turbine Building.

The new system was tied in on November 22 while operation at full power continued by connecting the common air header to each minimum flow valve one at a time. The tie in was accomplished by closing the associated minimum flow isolation valve (1-FW-15A, B, & 149C). The system was leak checked and tested to assure the air bottles alone could operate the minimum flow valves.

The inspector reviewed the PDCR package and associated safety evaluation and installation procedure (SP 89-1-46). The inspector also witnessed work activities in progress to install and test the new air header. The inspector also verified the installed hardware agreed with the PDCR drawings and design description. No inadequacies were identified.

6.2 Feed Pump Discharge Check Valve Seat Retainers - Unit 1

On October 19, the reactor scrammed as a result of a water level transient caused when the "A" feedwater regulating valve (FRV) failed in the "open" position. Upon disassembly of the FRV, a bolt was found in the lower area of the valve body below the cage assembly. The bolt was identified as coming from the "A" feedwater pump discharge check valve, 1-FW-2A. Additional work orders were written to inspect all three feedwater pump discharge check valves. One bolt and locking assembly was found missing from the "A" valve, and the second hold down bolt was loose allowing the valve disc to be cocked in its seat while in the closed position. The "B" and "C" hold down assemblies were found intact and secure.

Previous History

On December 5, 1984, a similar event occurred when the "B" FRV stuck in mid position. Disassembly revealed a bolt that was from the feed pump discharge check valve. The "A" valve was opened and all the bolts were in place, however, the lockwire was found missing. The "C" valve was then opened and it was found to be missing the bolt assembly. PIR 50-84 documented the failure and corrective actions. The lockwire size was increased. A lock wire procedure had been previously developed and was again used for this work effort. A check of the lockwire installation was made a quality control verification step.

As a result of the 1984 event, routine disassembly of at least one valve was included in the PM program for each refueling outage. The following was observed during those inspections: (a) During the 1985 refueling outage, the "A" valve was opened and inspected. No abnormalities were observed. (b) During the

1987 refueling outage, the "D" valve was opened and new pins and bushing for the hinge pins were installed. No problems with the retaining assembly were noted. The "A" valve was also disassembled to allow inspection of the discharge piping. Problems were noted with the seat and disc, and this assembly was replaced. No problems with the retaining assembly were noted. (c) During the 1989 refueling outage, the "C" valve was inspected and minor repairs to the under seat surface were made. No problems were noted with the retaining assembly.

Present Corrective Action - Design Change 1-32-89

The licensee worked with the valve manufacturer to redesign the bolt keeper assembly. The lock wire arrangement was replaced with a tabbed locking plate and locking tab to prevent the bolt from turning. The new design increased the anti-rotation capability of the keeper assembly by 7 times over the old design. The new keeper design was installed in the discharge check valves for all three feedwater pumps.

Because of the recurrence of the problem observed in 1984, the licensee re-evaluated the locking mechanism. The manufacturer was contacted to see if problems had been encountered before, or if a proposed modification could be offered. The licensee suggested that a lock tab arrangement be utilized and the vendor concurred. NPRDS was searched to determine if there were other reports of problems of this type with feedwater discharge check valves. Essentially, all the NPRDS items were from Millstone 1, and the other items were not relevant.

Several other problems were noted with the retainer assembly during the valve disassembly. The helicoil in the valve body of the missing bolt was partially unthreaded from the body. Also, the bolt found in the FRV was 1/2" shorter than the replacement bolt. Thirdly, the replacement retainer plate was flat. This was a problem because the seat surface is raised with respect to the valve body and thus a flat retainer plate would not seat perpendicular to the retaining bolt. This would not allow proper compression of the retaining bevel washer and even load distribution, and thus proper preload might not be maintained during operation.

To address these concerns, several changes were made per PDCR 1-32-89. The lockwire was replaced with a lock tab arrangement. New retainer plates were fabricated and hand fit to ensure that the plate and the bolt were perpendicular so that proper compression and preload could be applied to the retainer bolt. A "foot" was added to the bottom of the plate to prevent the entire assembly from rotating, since rotation of the entire assembly could also cause the bolt to loosen. The maintenance procedure was revised to reflect the use of the lock tab arrangement in place of the lockwire system.

During the reassembly, new helicoils were installed in both bolt holes of the "A" valve. No other helicoil problems were noted with the other valves.

Adequacy of Corrective Action to Prevent Recurrence

The licensee concluded the changes made per PDCR 1-32-89 were adequate to address the design problems of the valves. The licensee will inspect all three valves during the 1991 refueling outage. Additional clarification will be added to the applicable maintenance procedure to address the use of the unique hand fit parts so that future correct installation will be assured.

Several other valves in the reactor water cleanup system have a similar type retaining mechanism. These valves are smaller than the feedwater valves. No problems have been observed with their operation since 1984 based on licensee review of the PMMS history data base. These valves will be reviewed to determine what type of inspection program is appropriate and the frequency of any proposed inspections. There are no other Crane Model 1573 valves in Millstone 1.

Subsequent Actions - Units 1 and 2

The inspector requested the licensee to address the status of his actions in response to INPO SOER 86-03 regarding check valves installed in the plant. The licensee stated that actions had generally been taken to address the SOER. No comprehensive design reviews as requested by the SOER were done or deemed necessary in light of the extensive number of plant service years that had proven the adequacy of the installed equipment. Emphasis was given to improve the inspection and preventive maintenance programs, which included the periodic inspections of the feedwater check valves in the 1985, 1987 and 1989 outages. Following the INPO evaluation in August 1989, the licensee was requested by INPO to review its check valve program and to improve it as necessary.

The inspector reviewed the licensee's check valve program in relationship to Significant Operating Experience Report (SOER) 86-03 dated October 15, 1986. SOER 86-03 recommended establishment of a preventative maintenance program to: (1) identify the scope of valves included in the program based on plant experience; and, (2) assurance of check valve reliability by a combination of testing, surveillance monitoring, or disassembly and inspection on a sampling basis. The SOER 86-03 also recommended a design review of the current valve installation.

At Unit 1, eighty check valves were selected by the licensee in response to SOER 86-03. The valves were located in the following systems: condensate, feedwater, reactor water clean-up, core spray, low pressure coolant injection, service water, emergency service water, turbine building component cooling water, diesel generator air start, reactor building component cooling water, and containment air valve systems. A particular check valve was categorized by importance to reliability and safety based on overall system operability, redundancy, and historical data for reliability. Approximately 8% of the total valves inspected are subjected to an in-service inspection as required by ASME Section XI.

At Unit 2, sixty-five valves, located in the service water, main steam, feedwater, reactor building component cooling water, diesel generator air start, charging, low pressure safety injection, high pressure safety injection, safety injection tanks, and containment spray systems, were selected in response to SOER 86-03. Approximately 91% of the identified valves are subjected to in-service inspection prescribed in ASME Section XI, and 32% are subjected to a routine preventative maintenance.

The inspector reviewed Millstone 3 maintenance procedures for activities associated with various types of check valves. The following procedures apply: MP 712.2 "Disassembly/Reassembly of 1573 Pressure Seal Tilting Disc Check Valve," MP 716.2 "Overhaul of Globe, Gate and Check Valves," MP 719.3 "Anchor Darling Air-Assist Swing Check," and MP 743.10 "Diesel Generator Start Air Check Valves." The program is also inclusive of in-service inspections, and integrated leak rate testing.

At the end of the inspection period. the licensee was making preparations for an outside contractor to re-review the safety-related check valve program. The review will use the EPRI RP 2230-20 ±Industry Owners Group Guidance to SOER 86-03 guidelines to evaluate the check valve design vs. the current installation. The conclusion will input into the utilities preventative maintenance and/or plant design change record process (i.e. modifications).

The inspector reviewed 30% of the selected check valves described in the SOER 86-03 to evaluate the corrective and preventative maintenance activities on a case-by-case basis. Significant corrective maintenance activities on the Millstone 1 feedwater discharge check valve was identified.

A review of Unit 2 maintenance procedures for activities associated with various safety-related check valves was undertaken. Three principal maintenance procedures are developed to inspect and disassemble check valves. The procedures are MP 2702C1 'Standard Swing Check Valve Maintenance,' MP 2702C2 'Lift Check Valve Maintenance' and MP 2702 H2 'Main Steam Isolation Valve Check Valve Overhaul.'

The inspector reviewed the maintenance history via the Production Management Maintenance System (PMMS) since 1985 on approximately 15% of the check valves identified in the licensee's prescribed SOER 86-03 response. The valves are located in the service water, main steam, feedwater, charging, safety injection and containment spray systems.

Of the 10 randomly selected check valves, two (2-SW-1A and 2-MS-4B) documented corrective maintenance associated with defective internal valve parts. Valve 2-MS-4B (auxiliary feedwater steam supply to the terry turbine) required numerous maintenance activities associated with readjustment of valve balance, and excessive chattering. The licensee replaced 2-MS-4B with a newly designed valve (internally counter-weighted swing check) in March 1988. Further licensee actions and inspector concern are documented in report detail 5.1.3.

Training on the EPRI design guidelines was provided to both Units 1 and 2 staff engineering personnel. Procedure NEO 5.05 includes guidance on the application guidelines in the design review checklist.

In conclusion, the licensee has initiated actions to further develop a check valve inspection and maintenance program and the engineering design review was still in the developmental phase at the close of the inspection. The importance of implementation of the program is manifested in examples per report detail 5.1.1, 5.1.2, 5.1.3, 3.6 and 6.2.

In light of the October 19 event at Millstone 1, and the November 1 event at Millstone 2 involving the auxiliary feedwater steam supply check valve (2-FW-4B), the licensee was requested to more fully address the status of its plans to improve the check valve inspection program at Millstone Station. This matter is considered an unresolved item pending further review during a subsequent routine inspection to verify licensee programs, present or planned, are adequate to assure the continued operability and adequate performance of check valves installed in safety systems, or that could affect the operation of safety related systems (50-245/89-25-03; 50-336/89-23-01).

6.3 <u>Operability of Low Pressure Coolant Injection 480 Volt Swing Buses - Unit 1</u>

NRC Region I notified the inspector on October 18 of a potentially generic BWR problem identified at another facility concerning the undervoltage failure of the low pressure coolant injection (LPCI) swing buses. The inspector noted that Millstone 1 might be susceptible to the same problem due to the LPCI loop selection logic and the use of 480 VAC swing bus design, which is similar to the other facility. This matter was referred to the licensee for review.

It was determined at another facility that an assumed failure of the diesel generator voltage regulator could result in a range of undervoltage conditions at the 480 VAC swing bus such that the voltage is low enough to affect operation of the bus loads but not low enough to cause the swing bus to transfer. The safety significance of the issue is that the equipment on the degraded bus could not be assured, and transfer to the unaffected (operable) Class 1E emergency power source would not occur. This degradation would put the plant in an unanalyzed condition because the LPCI system and one of two core spray systems would be unavailable in the event of a loss of coolant accident with a concurrent loss of offsite power.

The licensee determined that Millstone 1 electrical design was not the GE standard LPCI swing bus, because in addition to the undervoltage (uv) protection supplied at the 4KV level, an additional level of undervoltage protection was provided at the 480V swing bus on Millstone 1. In the faulty design, the assumed regulator failure would produce voltages in the 50% to 80% range, which would degrade the associated 4KV motor loads, but not be low enough to cause the automatic bus transfer (ABT) switches to swap the MCCs and associated valves to the alternate supply. At Millstone 1, solid state undervoltage monitors are provided on the EF3 and FE3 swing buses that are set to pick up at 95% of nominal (456 volts) and drop out at 90% (432 volts). Thus, when voltage on the affected 480 volt bus drops to 90% of nominal, the uv protection causes the ABT solenoid controls the transfer to the unaffected 480 volt bus to assure continued operability of the MCC loads.

The inspector reviewed the bases for the licensee's conclusions, which included interviews with licensee personnel, a review of engineering drawing 25202-39010 - Sheet 129 and inspection of the undervoltage trip devices (ACC 48X relays) in 480 volt MCC2-3NE(EF3). Based on the above, the inspector concluded the problem was not applicable to Millstone 1. Engineering support to resolve this issue in a timely manner was excellent. No inadequacies were identified.

6.4 Inservice Testing

6.4.1 Pressurizer Heater Sleeve Inspection - Unit 2

On September 25, another utility presented to the NRC a description of pressurizer heater sleeve cracking and the nondestructive and metallurgical evaluations to determine the root cause. A Northeast Utilities (NU) representative attended the meeting between the utility and the NRC.

On May 5, 1989, the facility identified pressurizer heater sleeve leakage on approximately twenty (20) sleeves by the presence of boric acid deposits. The sleeve fabrication and base material are identical between the facility and Millstone 2. The only difference in sleeve material is the yield stress property. The affected facility has a yield stress of 63KSI and Millstone 2's yield stress is 43KSI for the inconel material. The determined root cause for cracks in the pressurizer heater sleeves was attributed to Primary Water Stress Corrosion Cracking (PWSCC).

There are one hundred twenty (120) pressurizer heaters at Millstone 2. The pressurizer heaters are single-unit, direct immersion heaters which protrude vertically into the pressurizer through sleeves welded in the lower head. Each heater is internally restrained form high amplitude vibrations and can be individually removed for maintenance during plant shutdown. Approximately 20 percent of the heaters are connected to proportional controllers which adjust the heat input as required to account for steady state losses and to maintain the desired steam pressure in the pressurizer. These heaters are separated into two banks (150 kW each) and are provided with diverse vital power.

On October 27, as a result of the heater sleeve leakage at another facility, the licensee conducted an ASME Section XI, VT-3 visual examination. The visual examination focussed on the heater sleeve penetrations, and was completed by two level II VT examiners. The licensee documented the results of the inspection using engineering procedure NU-VT-1 and authorized work order (AWO) M2-89-11543. The inspector accompanied the examiners on the inspection. No leakage from the pressurizer heater sleeves was identified. Inspector review also verified the adequacy of tag-out 2-2880-89, pre-brief meeting, observed health physics controls, and visual inspection techniques and documentation results. The inspector concluded that the overall activity of the pressurizer heater sleeves was sufficient and well prepared. No further questions were developed at this time.

6.4.2 Steam Generator Eddy Current Testing (ECT) Examinations Unit 2

On August 30, the utility documented the steam generator ECT scope and acceptance criteria for the mid-cycle outage beginning on October 21, 1989. The documented inspection scope included all unsleeved tubes in the crack region. The crack region was based on previous licensee history of SG tube crack location and sludge pile height. Two ECT probes were utilized; bobbin coil (tube pit indications) and the rotating pancake coil (RPC) (circumferentially oriented cracks). Further ultra-sonic testing was implemented to further characterize the tube defect based on the bobbin and RPC probe signatures. On October 10, the NRC accepted the utilities proposed inspection plan based on the August 30 documented inspection plan. The tube inspection was not considered a required surveillance activity as specified in TS 4.4.5.0 except for the repair of defective tubes prescribed in TS 4.4.5.1.4.a.

The initial inspection scope consisted of the following percentage of available SG tubes prior to the inspection.

-- No. 1 SG - 54% (3762 tubes)
-- No. 2 SG - 49% (3623 tubes)

The initial inspection scope was expanded by a total of 513 combined SG tubes. The expansion was completed to maintain a border of three uncracked SG tubes along the perimeter of the inspection region. The inspector verified the expanded scope was adequate based on a review of SG plenum diagrams showing tube indications and expansions.

On November 6, the licensee completed ECT examinations for both SGs. The final inspection results are summarized as:

-- SG#1 - 104 tube cracks; 74 tube pits
-- SG#2 - 11 tube cracks, 37 tube pits

All tube cracks and pits were classified as defects as prescribed in TS 4.4.5.1.4.a.5. (i.e. greater than 40% nominal wall thickness crack). The classification of tube defects were based on independent analysis review, and two senior analysts collectively calling a defect. The final decision was based on March 9, 1989 RPC results, bobbin coil results, RPC results, and ultrasonic evaluations. An NRC specialist inspection during November 7 - 9, 1989, further reviewed the results of SG ECT at Millstone 2 as documented in Inspection Report 50-336/89-20.

6.5 Engineering Design for Anchor Supports on the Service Water Strainers - Unit 2

During February, 1989 the Millstone 2 engineering staff conducted a visual and dimensional inspection of the service water component baseplates. The inspection was initiated as a result of an early 1988 licensee safety system functional inspection (SSFI). The purpose of the visual/dimensional walkdown was to identify degraded hold-down bolts due to the corrosive salt-water environment. Based on the walkdown results, the engineering staff evaluated and determined acceptability of the hold-down bolts. On September 20, 1989, the results of a quality assurance audit were published which called into question the method of analysis used to resolve an as-found condition regarding the anchorage of the service water strainers. In an engineering response to the audit findings on October 23, 1989, a conclusion was reached that continued operability was justified, pending further evaluation of the strainer calculations. This evaluation was committed to be completed by November 22, 1989. During the evaluation NNECO identified two discrepancies with the original vendor's structural qualification of the strainers.

The discrepancies were: (1) the as-built configuration was not reconciled between the SW strainer vendor analysis and the architect/engineer's analysis, and (2) the input response spectra was not properly amplified to the appropriate building elevation at which the piping was supported. The above discrepancies invalidated the seismic qualification. Specifically, the expansion anchor bolt assemblies for the service water strainers were below a factor of safety of four as prescribed in NRC bulletin /9-02.

The licensee completed the installation of additional seismic supports for the service water strainers under plant design change 2-22-89. Each of the supports consists of two vertical structural columns with welded cross members all attached to the flange of the 24 inch pipe outlet of the strainer. The vertical structure column is welded to the base plate. The baseplate is anchored to the floor by four under-cut fasteners.

A review of corporate engineering calculation MP2-114-1227GP included a verification of select support leg evaluations, baseplate evaluation, and modeling techniques. The evaluation was consistent with the original architect-engineer methodology, and the seismic loads under a design basis earthquake were considered simultaneously in the X, Y, and Z directions. The inspector had no concerns in the support leg evaluation and strainer modeling techniques.

The original baseplate configuration consisted of two expansion anchor bolts (Hilti) and two embedded anchors. The additional support baseplate consisted of 5/8-inch and 3/4-inch Drillco Maxi-Bolts. The anchor embedment varied between six and seven inches depending on the diametric bolt size. The engineering calculation determined the most-limiting stress area for the baseplate was on strainer L-1A. The allowable load under the design conditions is 19,221 lbs. The worst case loading on the bolt is 9508 lbs. in tension and 1655 lbs. in shear. The licensee used a stress interaction formula to qualify bolt acceptance with the following:

$$\frac{9508 \text{ lbs.}}{19221 \text{ lbs.}} + \frac{1655 \text{ lbs.}}{9969 \text{ lbs.}} = .6681$$

NRC Bulletin 79-02 limits load on expansion anchors to 25% of the average ultimate capacity. The additional strainer support increased the margins to safety on the original bed plate from less than four to an excess of twenty-one based on the evaluated stress; however, the additional support margins were less than prescribed in NRC Bulletin 79-02. Previous NRC review of Bulletin 79-02 was documented in inspection report 50-336/85-01.

On May 29, 1985 the utility documented to the NRC its intent to use Drillco Maxi-Bolt Concrete Anchors without the design margin prescribed in Bulletin 79-02. The design margins conform to American Concrete Institute Manual of Concrete Practice for Nuclear Safety Related Structures (ACI on 349-77), and specifically Appendix B "steel embedments". Appendix B sets forth criteria to ensure ductile failure of the anchor bolt governs the design rather than failure of the concrete surrounding the bolt. The Drillco Maxi-Bolts differ from the typical expansion in that a bearing force is established in the concrete versus a parallel surface in the direction of tension loads. The application of the Drillco Maxi-Bolts was committed to and implemented by the licensee in the service water strainer support modification.

The acceptability of the design methodology in application of Drillco Maxi-Bolts was questioned by the NRC staff. Specifically, NRC Regulatory Guide 1.142 establishes AC/N349-76 as acceptable to the staff except for endorsement of Appendix B. The licensee has not specifically committed to NRC Regulatory Guide 1.142. The primary objection to the application of Maxi-bolts are base plate flexibility, and lack of dynamic qualification reports. Based on this objection to the application of ACI 349-76 Appendix B engineering code, the NRC requested the licensee to implement an interim program of inspection and verification, and to identify the scope of the application of the specific anchor assemblies. The licensee did not accept the proposed commitment, however, it did identify the scope of applications at the Millstone Station, and visually examined a random sample. At Millstone 1, the bolts are used in the core spray pump and low pressure safety injection pump foundations; At Millstone 2, the bolts are only used in the service water strainer supports; and at Millstone 3, no maxi-bolts are used in safety applications.

The inspector reviewed the safety evaluation and unreviewed safety question determination under PDCR 2-22-89. The utility determined the modification was safe and was not an unreviewed safety question as prescribed per 10CFR50.59.

In conclusion, the acceptability of ACI 349-77 Appendix B with the application of Drillco Maxi-Bolts will be referred to the Office of Nuclear Reactor Regulation for its evaluation. The acceptance of the design in the short-term is based in part on (1) overall improvement in the installation of additional service water supports; (2) no discernible degradation of the bolts during service at Unit 1; (3) licensee determination that no unreviewed safety question exists; and, (4) minor safety significance in the explicit differences in design methodology for anchor bolt assemblies in the accident conditions. Final resolution of this item is unresolved (50-336/89-23-02).

6.6 Previously Identified Items

6.6.1 (Closed) Unresolved item 50-245/88-17-01: Emergency Service Water System Classification as Engineered Safety Feature System and QA Category I Components

This item involves licensee failure to classify the emergency service water (ESW) system as an engineered safety feature (ESF) system in emergency plan implementing procedure (EPIP) form 4701-7, which lists Millstone 1 ESF systems, and questionable classification of certain ESW strainer components in the Millstone 1 Material Equipment and Parts List (MEPL).

Since ESW is an integral part of systems required to assure successful core and containment cooling following design basis accidents, the inspector considered classification of the system as an ESF to be appropriate. In response to this concern, the licensee issued revision 1 to EPIP Form 4701-7, dated May 16, 1989, listing ESW as a Millstone 1 ESF system.

In response to NRC inspection report 50-245/87-03, the licensee implemented plant design change request 1-87-87 to provide safety-related power supplies for the ESW strainer motors and backwash solenoid valves. However, the inspector noted that certain ESW strainer components, and blowdown solenoid valves, were not classified in the Millstone 1 MEPL as QA Category I, indicating an inconsistency in the licensee's treatment of the ESW strainer safety function.

The inspector reviewed licensee MEPL evaluation number CD 3168, dated August 4, 1989 and determined that the applicable ESW strainer components have been classified as QA Category I.

This item is closed.

6.6.2 (Closed) 50-245/88-17, Detail 4.1: Low Pressure Coolant Injection Minimum Flow Valves

On August 29, 1988, while performing a routine tour of the Millstone 1 control room, the inspector discovered "A" low pressure coolant injection (LPCI) minimum flow valve 1-LP-26A in the shut position, rather than open as required by procedure. During routine follow-up, it was determined that periodically the LPCI minimum flow valves had not operated properly due to degraded actuating flow switches. Due to the unavailability of spare parts and the unreliability of the switches, the licensee initiated a plant design change request (PDCR) to block open the minimum flow valves permanently by removing the flow switches and modifying the valve actuation circuitry.

The LPCI system is an emergency core cooling system designed to provide low pressure, high volume coolant makeup to the reactor in the event of a loss of coolant accident (LOCA). The system also provides post-accident long-term containment cooling capability. The minimum flow valves 1-LP-26A and 1-LP-26B recirculate a portion of LPCI pump discharge flow to the torus in order to protect the pumps from damage due to overheating, cavitation, or excessive vibration.

The inspector reviewed PDCR MP1-07-89, Revision 0 and its associated safety evaluation to determine the impact of the modification on system response to design basis accidents; i.e., the ability to deliver the required flow to the reactor when challenged, while ensuring adequate cooling flow to the pumps. Also reviewed were licensee calculation W1-517-836-RF, Millstone 1: Acceptability of LPCI and CS Flow with Diesel Generator 5% Droop and Instrument Uncertainty, dated March 25, 1988, the results of test procedure T-88-1-6, LPCI/CS Minimum Flow Verification, Revision 0, dated December 19, 1988, and the results of surveillance test SP 622.10, LPCI System Narrow Range Flow Verification, Revision 0, dated February 16, 1989.

The minimum acceptable LPCI system flow to the reactor vessel following a design basis LOCA has been determined by General Electric Company to be 4370 gpm per pump at 20 psig vessel pressure. Surveillance procedure SP 622.7, LPCI System

Operability Test, Revision 13, dated February 17, 1988, specifies a minimum acceptable pump flow of 5000 gpm at 80 psig pump discharge pressure, and is consistent with section 6.3 of the Updated Final Safety Analysis Report. In order to reconcile these flow requirements, allowance is made for pump operating point (83 gpm), flow instrument error (142 gpm), and emergency diesel generator speed droop penalty (359 gpm). Hence, the minimum acceptable LPCI flow is: 4370 + 359 + 142 - 83 = 4788 gpm at 80 psig pump discharge pressure, allowing a 212 gpm margin to 5000 gpm. Special Test T-88-1-6 recorded a maximum bypass flow of 130 gpm at 270 psig pump discharge pressure with minimum flow valves open. Adjusting for 80 psig discharge pressure, the final flow diverted is 71 gpm, well within the 212 gpm margin.

In order to assure that cooling flow is available to the LPCI pumps, the valve-open circuits of 1-LP-26A and 1-LP-26B were modified by the PDCR to actuate upon automatic start of the pumps. Procedures associated with manual start of the pumps were modified to check the valves open prior to operation.

As a result of the review, the inspector determined that the system modification had no adverse affect on the ability of the LPCI system to respond adequately to a design basis LOCA. This issue is closed.

6.7 Summary

Millstone 1

Two open items (50-245/88-17-01 and 50-245/38-17 detail 4.1) were closed.

Licensee engineering evaluation of the operability of the LPCI swing bus relating to undervoltage failure was assessed as a strength.

Millstone 1 and 2

Two unresolved items were opened. One item (50-245/89-25-02 and 50-336/89-23-01) identified the licensee's program to adequately assure continued operability and performance of check valves installed in safety systems, and the second item (50-336/89-23-02) will review resolution of design margins for seismic support anchors.

7.0 Security

Selected aspects of site security were verified to be proper during inspection tours, including site access controls, personnel searches, personnel monitoring, placement of physical barriers, compensatory measures, guard force staffing, and response to alarms and degraded conditions. No inadequancies were noted.

8.0 Safety Assessment/Quality Verification

8.1 Committee Activities

Plant Operations Review Committee - Units 1 and 2

The inspector attended meetings of the Millstone 1 Plant Operations Review Committee (PORC) on November 2, November 6, and November 30. The inspector attended meetings 2-89-170, 2-89-171, 2-89-183, 2-89-192, 2-89-193, and 2-89-197 of the Millstone 2 Plant Operations Review Committee (PORC) meetings on October 31, November 1, November 13, November 20, November 21, and December 1, respectively. The inspector noted by observation that committee administrative requirements were met for the meetings, and that the committees discharged their functions in accordance with regulatory requirements. The inspector observed a thorough discussion of matters before the PORC and a good regard for safety in the issues under consideration by the committee. No inadequacies were identified.

Site Operations Review Committee (SORC)

The inspector attended a SORC meeting on November 21. The SORC meeting fulfilled the responsibilities as required per technical specification 6.5.2.6. The inspector observed a thorough discussion of matters before the SORC and a good regard for safety in the issues under consideration by the committee.

8.2 Periodic Reports

Upon receipt, periodic reports submitted pursuant to technical specifications were reviewed. This review verified reported information was valid and included the required NRC data. The inspector also ascertained whether any reported information should be classified as an abnormal occurrence. The following reports were reviewed:

-- Monthly Operating Report - October, 1989.
-- Monthly Operating Report - November, 1989.

8.3 Summary

The inspector observed discussion of matters before PORC and SORC with a good regard for safety.

9.0 Reactive Inspection Activities

9.1 Allegations Presented to the Utility for Resolution - Unit 2

On November 8 and December 4, the inspector presented various concerns from employees at Millstone station to licensee management for resolution. Appendix A to this inspection report lists the issue number, the date received by the NRC, the alleged concern and, in some cases, licensee and NRC actions taken since receipt.

Licensee actions to respond to employee concerns will be reviewed further in subsequent routine inspections. No inadequacies were identified in licensee responses to date for the matters listed in the appendix.

9.2 Fitness for Duty (Regional Temporary Instruction 88-01)

This inspection is a followup to Region I Temporary Instruction 88-01, as well as a review of the Initial Fitness for Duty Training Program for preparation for implementation of the new rule requirements of 10 CFR 26.

The Northeast Utilities (NU) Fitness for Duty Program is applicable to all NU system employees, contractor and vendor personnel and individuals who require unescorted access and/or who are required to respond to emergency facilities. The program is also applicable to contractor and vendor personnel performing duties as interstate commercial vehicle operators at NU system companies.

The licensee will have all personnel trained in its Fitness for Duty Program and will have the program implemented in December, 1989, with full implementation by January 1990 as required by the rule. The Fitness for Duty Manual was to be distributed to all employees by December 3, 1989.

As of November, 1989 NU had a policy of pre-employment testing for nuclear workers. NU did not have a random or "for cause" testing or testing as a result of supervisory referral for nuclear workers. This is because the State of Connecticut regulations forbid such programs. The rule change supersedes the Connecticut regulations and thus is effective after January 1990. Since October 1, 1987, two nuclear workers have been tested. No positive tests have been identified. Testing was done similarly as prescribed in the planned Fitness for Duty Program.

9.3 NRC Information Notice 86-106 (Regional TI 87-02) - Unit 2

This inspection is a selected followup to Region I Temporary Instruction 87-02 concerning followup on IE Information Notice 86-106, "Feedwater Line Break."

The licensee's immediate response to the Surry feedwater line break incident in December 1986 was from information received through the Nuclear Information Network. Millstone 2 engineering performed a limited scope wall thickness measurement program on the feedwater pipe while in the hot condition. The pipe section was chosen based on what was believed to be a similar configuration to Surry. This program showed that some wall thinning had occurred but no substantial wall loss.

At the time of the Surry event, Unit 2 had a wall thickness monitoring program of secondary side piping systems per procedure EN 21153. The procedure covered the following piping systems:

1. Heater Drain and Vents
2. Service water
3. Main Steam High Pressure Drains
4. Extraction Steam
5. Steam Generator Blowdown

The procedure was modified to include the feedwater system, the condensate system reboiler piping and the main steam piping. The procedure is a computerized system for tracking the condition of these piping systems. The base line inspections of the added systems were performed at the first outage which was in January 1987. The inspection consisted of UT examination of all areas of piping that would have potential for erosion due to flow conditions in the piping. Such areas included places of changes in direction of flow such as at elbows and tees, at reducers, at backing plates for welds, in sections where flow would be non laminar. Areas of suspected erosion greater than 30% are located for further analysis and more frequent inspection to determine the rate of degradation. Areas greater than 50% reduction would be recommended for removal and replacement.

During the January 1987 outage, wall thinning of less than 5% was identified at the inlet and outlet piping of the No. 1 feedwater heaters. The extent of this loss was not considered a problem for personnel safety or continued operation.

In response to supplement 2 of IE Information Notice 86-108, the licensee performed analyses of the effects and consequences of a feedwater line break on egress from the areas, on the card reader systems and on the actuation of the fire protection systems due to moisture. Due to the potential of card reader systems failure, several egress doors were changed to allow egress by panic bars. In the event of a break, it was determined that auxiliary feedwater would have to be initiated. There are no vital motor control centers in the turbine building. If the turbine batteries/chargers located in the turbine building were lost, automatic transfer to the primary supplies would occur. Moisture carryover into the instrument air system would be delayed and should not have significant effect on the event. The risk to personnel in the administration building due to steam in the turbine building was considered acceptable due to the low probability of the event.

9.4 Auxiliary Feedwater Discharge Check Valve Environmental Qualification - Unit 2

On November 10, the inspector received an allegation from a Northeast Utilities employee. The concern primarily dealt with the environmental qualification for the auxiliary feedwater discharge check valves 2-FW-12A and 2-FW-12B. The alleger's involvement in corrective maintenance work activities to replace a malfunctioning in solenoid operator on valve 2-FW-12B further identified discrepancies in the installation that negated the environmental qualification of the valve. The issues followed up by the inspector were:

- Are similar environmental qualification discrepancies located on the alternate facility valve 2-FW-12A?

- Was the licensee unresponsive in corrective actions based on previous EEQ walkdowns of valve 2-FW-12A?

The check valves are solenoid-operated, air-assist to close to assure positive closure as a containment isolation valve. They are located in the enclosure building, and are the outboard containment isolation valve for the auxiliary feedwater system. The valve operators receive no engineered safety feature signal, and are not recognized in the technical specification as containment isolation valves. The primary purpose of the valves are to prevent main feedwater from flowing into the auxiliary feedwater system during normal operation. The valve operators, cabling, solenoid valve, limit switch, junction box, and terminal blocks are identified in the EEQ master list.

The operation of the valve operator is as follows: when the solenoid coil is energized it applies air to compress the valve closing spring to ensure the check valve is closed.

Valve 2-FW-12B EEQ discrepancies identified by the licensee included: a non-approved splice (inline barrel) to extend the leads between the solenoid coil and the terminal board, no weep hole in the junction box, replacement of the solenoid coil, and unqualified lugs to terminate the extended wire to the terminal board. On November 9 the licensee prepared PIR 89-119 and non-conformance report 289-174 to document the EEQ discrepancies on the 2-FW-12B valve.

In the disposition of the non-conformance report the licensee reviewed the failure mechanism of the valve operator. During a high energy line break in the vicinity of the valve, steam would enter the conduit and reach the junction box. The steam would condense in the junction box and collect to either result in electrical shorts or grounds. The result would be to either prevent the solenoid from energizing, or deenergizing, or loss of limit switch position indication. The licensee's conclusion was that any of the faults reviewed would not prevent by itself the check valve from working as intended: allowing auxiliary feedwater flow to the #2 steam generator, and preventing back flow from the steam generator to the auxiliary feedwater system. The lack of EEQ for the valve results in a simple swing check valve. As required per 10 CFR 50 Appendix A General Design Criteria 57 each line that penetrates primary reactor containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, or locked closed, or capable of remote manual operation. A simple check valve may not be used as the automatic isolation valve. Final Safety Analysis Report 5.2.8.1.2.e, describes the general design 10 CFR 50 Appendix A criteria 57.

On December 4, the licensee generated an authorized work order to walkdown the EEQ configuration for the initially unaffected auxiliary feedwater check valve 2-FW-12A. The solenoid coil, cable, junction box, terminal board configuration differed from 2-FW-12B. Specifically, the as-built junction box did not have a terminal board and acted as a pull box; the junction box did have a weep hole; the pull box had a scotch tape splice for the lines to the solenoid; and the solenoid valve was EEQ. On September 5, 1989 the NRC issued information notice 89-63 to alert licensees that electrical circuits located above the plant flood level within electrical enclosures may become submerged in water because appropriate drainage has not been provided. The electrical enclosures addressed by this include terminal boxes, junction boxes, pull boxes, conduits, condulets, and other enclosures for end-use equipment the contents of which may include cables, terminal blocks, electrical splices and connectors.

The inspector accompanied the licensee on the EEQ walkdown of valve operator for 2-FW-12A. The inspector questioned the configuration of drainage of moisture in the as-built alignment, and the position of the weep hole.

The inspector reviewed a EEQ walkdown sheet for both valve operators for 2-FW-12A and 2-FW-12B during the 1986 timeframe. The configuration prior to corrective actions by the licensee was identified for valve 2-FW-12B, specifically the spliced cable within the junction box. The inspector questioned the licensee if information available at the time frame of the equipment walkdown was sufficient to detect an unacceptable configuration. This item will be tracked as an unresolved item pending licensee response (50-336/89-23-03). A review of licensee actions on (1) the purpose of EEQ for the auxiliary feedwater check valve operators and (2) EEQ acceptability based on walkdown of 2-FW-12A will be tracked as part of the open item.

9.5 Previously Identified Items

9.5.1 (Closed) UNR 50-245/87-05-03: Transient Equipment Storage in Safety-Related Areas

NRC Information Notice (IN) 80-21, dated May 16, 1980, requested that licensees of nuclear power facilities review the storage of non-seismic transient equipment having the potential to adversely affect safety-related equipment. In response to the IN 80-21, the licensee implemented administrative controls concerning the use of temporary staging, scaffolding, ladders, and wheeled equipment in safety-related areas of the plant.

Procedure ACP-QA-4.01, Plant Housekeeping, section 6.4.7, requires observation of the following seismic considerations when working near safety-related equipment:

-- Temporary ladders are to be tied off or otherwise secured.
-- Unanchored wheeled equipment is to be secured by curbs, chocks, or locking wheels.
-- Equipment with a high center of gravity is to be restrained against tipping.
-- Equipment shall be stored such that a falling hazard is not created, e.g., loose power tools or boxes stored above safety-related equipment.
-- Cranes or rotating booms should be secured when not in use to prevent sway or swinging interaction with safety-related equipment.

In 1987 an inspection of this issue was conducted pursuant to NRC Region I Temporary Instruction (TI) No. RI-87-03, dated March 5, 1987. As a result of this review, the inspector identified weakness in the implementation of this program and the need for a coordinated licensee approach to the issue.

Responding to the inspector's findings, license management conducted briefings of all station personnel on the requirement to secure equipment and scaffolding throughout the plant. Wooden chocks were fabricated for wheeled components, transient equipment was tied off, and mobile equipment was stencilled "chock when unattended". A program for the installation and removal of scaffolding in the vicinity of plant equipment was instituted with the promulgation of procedure ACP 2.19, Scaffolding Program. The procedure provides guidelines for the installation of scaffolding, requires that erection and removal of scaffolds be controlled by work order, and includes criteria for an engineering evaluation of scaffolds erected in the vicinity of safety-related or fire protection equipment.

Finally, the licensee performed a fire protection survey of the facility to review the seismic adequacy of fire protection equipment storage. At Millstone 1, a potential missile hazard was identified concerning the mounting of CO2 fire extinguishers. Strap-type truck mounting brackets have been ordered and a seismic analysis of bracket anchorage requirements is in progress.

The inspector considers these actions to be responsive to NRC concerns regarding IN 80-21. The inspector toured safety-related areas of Millstone 1 and determined that the licensee was generally in compliance with the relevant administrative controls. Scaffolding evaluations pursuant to ACP 2.19 were reviewed for work involving the repair of water tight seals on 125 volt motor control center 101 AB-2 and the extension of local leak rate test connections on electrical penetrations.

However, the following conditions were noted:

-- An unsecured I-beam was staged across a floor access opening directly above the "B" core spray pump in the northeast corner room of the reactor building.
-- An argon gas bottle on trolley M67-116 was not secured against tipping per ACP-QA-4.01.
-- A partially installed pipe hanger was attached to seismic Category I reactor feedwater piping in the feedwater control valve room.
-- A temporary ladder used during the removal and repair of a drywell nitrogen compressor pre-cooler was secured to a safety-related cable conduit.

The inspector noted the licensee's timely response to these items and had no further questions. NRC Region I TI No. 87-03 and this item are closed.

10.0 Management Meetings (IP 30703)

Periodic meetings were held with station management to discuss inspection findings during the inspection period. A summary of findings was also discussed at the conclusion of the inspection. No proprietary information was covered within the scope of the inspection. No written material was given to the licensee during the inspection period. The inspectors attended the Exit Meeting for IR 50-245/89-23 on November 3, 1989.

APPENDIX A

Allegations Presented to the Licensee Management for Disposition

Number	Date	Alleged Concern
A.15.01 A.18.01	July 12	The containment spray logic actuation signal is not subjected to a monthly functional test determining operability of the automatic test inserter, as requred by technical specifications. NRC previous follow-up of this issue was documented in routine inspection report 50-336/89-17.
A.16.01	July 19	Procedural non-intent change to Surveillance Procedure 2401E, indicates a potential for previous noncompliance in conducting SP2401C. The reason for the procedural change was to: (1) add steps to enable the computer to provide an incore analysis report, and (2) delete steps for the reactor regulating system channel and move the steps to another location in the surveillance procedure, in order to be able to correctly perform the surveillance.
A.20.01	August 18	Concerns during troubleshooting efforts with the control rod position indication (metroscope): specifically insufficient parts, inadequate training, and technical manuals.
A.20.02	August 18	The Final Safety Analysis Report update on description of plant area radiation monitors were inaccurate.
A.21.01	August 21	Improper resistance temperature detector (RTD)installation on the spare reactor coolant pump. The inspector observed actual RTD configuration and received a copy of the non-conformance report 289-157 detailing the discrepancy. A further concern resulted in the disposition of the RTD connection as a ±repair,' Quality Control involvement on receipt of the spare RCP motor, NRC notification and, timeliness of NCR initiation upon identification of the defect.

A.21.02	August 21	Improper setpoint change evaluations for procedure OP 2383C as it relates to the monthly functional calibration for the steam jet air ejector. OP 2383C cannot be performed as written.
A.21.02	August 21	Lack of source check prior to radioactive gaseous discharge for process radiation monitor RM-9095as requred per technical specifications. The licensee initiated PIR 89-89 on August 22 to document the lack of source check for RM-9095. On September 20, 1989 LER 89-07-01 was issued documenting a failure to conduct a source check for RM-9095.
A.23.01	August 29	A concern in procedure IC 2404AX if containment hydrogen purge valve movement is verified when the sensor is subjected to the setpoint radiation signal. The question if the required functional test is conducted in conformance with the TS definition of a functional test.
A.25.02	September 13	Two examples of potential procedure non-compliance (1) Emergency planning on-call and upgrade status and, (2) SP 2404S Auto Auxiliary Feedwater not performed as written.
A.27.02	September 22	During performance of SP-2401D on September 22 identified a test discrepancy, and when identified to the shift supervisor was told to continue testing.
A.27.02	September 22	Inspector reviewed technical discrepancy identified during performance of SP-2401D and concluded no safety or operability with the reactor protection system. The identification to the shift supervisor was to have the licensee remain sensitive to how conflicts are resolved. This concern was reviewed in inspection report 50-336/89-22.
A.29.01	October 19	Troubleshooting activities on radiation monitor RM 8262B a 10K ohm potentiometer was identified across the meter leads. No update drawings or explanation identified the potentiometer. A Non-Conformance Report was issued to address corrective actions.

A.29.02	October 18	During the performance of procedure SP 2404AL an isotopic check was unable to be performed.
A.29.02	October 18	As prescribed in the procedure, the licensee generated a procedural change on October 18, and PIR 89-107 was issued.
A.31.01	October 30	The alleger was concerned with corrective maintenance work on a circuit board for containment process radiation monitor RM-8262B during the week of October 21. Specifically, the alleger replaced chips/resoldered clips on the circuit board. This removed conformal coating on a portion of the circuit board. The alleger approached licensee engineer about the removal of conformal coating from the board. The alleger, after discussions with the engineer, processed an NCR to disposition the issue. QC reviewed and assigned a number to the NCR. The engineer, upon receipt of the NCR, told the alleger, "do not issue an NCR unless it is explicitly known of a non-conformance to a requirement."
B.10.1 B.10.3	August 4	Alleger ... ded resident inspector concerns with Pl... sign Change Evaluation control; equipmen... gging question on fuel handling build... ; and configuration of anti-... nal device on spare reactor coo... p motor. The inspector at the time of the allegation called the control room operators to verify adequacy of the equipment tagging item on he fuel handling building fan. Equipment tagging verified acceptable. On October 6, the inspector on the status of the spare RCP motor, in regard to the hoses to the reverse rotation DP transmitter, they were removed by GE during installation of the new tilting pad upper guide bearing in Memphis, Tennessee. The hoses were reconnected by the GE field representative at Millstone. The spare RCP motor has been assembled/rotated with the lift pump. The run was successful. ISI flywheel preservice inspection will be completed prior to installation.

B.11.1	August 14	Alleger provided inspector a memo concerning numerous apparent non-compliance of SP-EE-076; MP-2701J Lubrication program omissions; and non-compliance to specification requirements as it relates to MP2701J preventative maintenance activities.
B.12.1	August 23	A controlled 'red-tagged' lighting panel breaker found by the alleger to be in the incorrect position for approximately a two-week time frame. Licensee aware of red-tag discrepancy. Revising radwaste building electrical panel schematics.
B.13.1	September 5	Wrong power supply identification in the PDCE MP2-89-076 (MRRF Building) modifications. The MRRF Building is a radwaste storage facility.