U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-423/86-21

Docket No. 50-423

License No. NPF-49

Licensee: Northeast Nuclear Energy Company
P.O. Box 270
Hartford, CT 06101-0270

Facility Name: Millstone Nuclear Power Station, Unit 3

Inspection At: Waterford, Connecticut

Inspection Conducted: June 24 - August 11, 1986

Inspectors: J. T. Shedlosky, Senior Resident Inspector
F. A. Casella, Resident Inspector
E. M. Conner, Project Engineer

Approved by: E C McCabe
E. C. McCabe, Chief, Reactor Projects Section 3B
8/15/86
Date

Inspection Summary:

Areas Inspected: Routine on-site resident inspection (115 hours) of shutdown planning, plant operations, radiation protection, physical security, fire protection, surveillance and maintenance.

Results: This inspection identified satisfactory performance in all areas.

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DETAILS

1. Summary of Facility Activities

For the first 4 and 1/2 weeks of this inspection period, the plant maintained approximately 100% power, attaining a capacity factor of over 91% with 73 days on line. Fuel burnup exceeded 3000 MWD/MTU on June 25 and flux distribution limits were modified accordingly. On July 10, NRR approved termination of shift advisors on July 15, when hot operating experience for all operators would meet license conditions. That termination was accomplished.

Reactor Coolant System loop 2 Hot Leg RTD system response time was declared excessive and the 6 protective system bistables fed by it were tripped on July 11.

A significant operational transient occurred on July 21 when all moisture separator reheat drain tank level control valves tripped shut, resulting in a low suction pressure trip of one of two operating feed pumps. Operator response was quick and accurate; feed system control was recovered and a plant trip was averted.

An ENS notification was made on July 24 to report a Control Building Isolation (ESF actuation) due to a "B" train chlorine monitor high chlorine signal. The actuation was spurious and the signal was reset prior to Control Room pressurization.

During this period, unidentified leakage within the containment was increasing as indicated by calculation, sump flow rates and containment atmosphere activity levels. There were problems with the unidentified leak rate computer program, these were resolved. During the subsequent shutdown, forty-one packing leaks were discovered in containment. Approximately 44 mechanical snubbers were replaced due to boron crystal contamination after failing to pass the technical specification visual inspections performed during the outage.

An identified leak exceeding the 10 gpm technical specification limit initiated an unplanned outage on July 24. In this instance, slave relay testing was in progress to assure proper functioning of Containment Isolation Valve (CIV) circuitry. The letdown CIV outside containment was shut without first shutting the letdown isolation valves. The 600 psi relief between the two CIVs was thereby subjected to full RCS pressure. That lifted the valve and caused flow damage to the nozzle, seat, and disc. This damage prevented reseating of the valve and resulted in 11 to 15 gpm of identified leakage to the Pressurizer Relief Tank. The shutdown to Mode 5 commenced at 1836 on July 24.

While shutting down, the plant experienced a feedwater isolation (FWI) on high steam generator level followed by a reactor trip on low steam generator level. These were both brought about by a loss of manual feed control while shifting from the main regulating valves to the bypasses. The FWI did not trip the "A" Turbine Driven Feed pump as it should have by design.

While cooling down from Mode 3 to Mode 5, a safety injection (SI) occurred when a momentary loss of the SI block occurred. About 400 gallons of borated water were injected before the SI was reset and equipment secured. The loss of block signal occurred twice more during "A" Emergency Diesel Generator operation. There was no additional injection of water into the RCS. Proper SI performance was restored by removal of interference from an SI relay contact.

Other plant components were in need of corrective maintenance. The licensee elected to extend the outage to incorporate these items as well as cold shutdown surveillances that would come due by the planned February 1987 mid-cycle outage. Major activities included replacement of all three pressurizer code safeties, repair of both pressurizer power operated relief valves, replacement of a main generator high voltage bushing; removal of steam strainers from turbine stop, control and control/intercept valves; weld repair of feed pump recirc control valve bodies, correcting the settings of all main steam safety valve blowdown rings, changeout of "A" Emergency Diesel Generator (EDG) fuel oil and 100% inspection of plant snubbers.

Cold shutdown surveillances, local leak rate testing (LLRT), RCS closure joint inspections and valve in-service tests were also performed. Two Reactor Plant Chilled Water CIVs failed LLRTs due to seat erosion and were rebuilt. A Residual Heat Removal isolation valve (RHR 8701B) appeared to have failed its stroke time test. It was found on further review to be acceptable; the problem was in the acceptance criteria.

On August 4, during a full load surveillance, the "B" Emergency Diesel tripped for no apparent reason. The licensee found no problems with the unit, reran the operability surveillance, could not duplicate the trip, and declared "B" EDG operable.

At the conclusion of this report period, recovery from the outage was underway with the plant in Mode 5, preparing to enter Mode 4.

2. <u>Review of Plant Operations</u>

The inspector observed plant operations during regular and back shift tours of the following:

Control Room	Fence Line (Protected Areas)
Auxiliary Building	Yard Areas
Diesel Generator Building	Turbine Building
Intake Structure	Vital Switchgear Areas
Main Steam Valve Building	Electrical Tunnels
Waste Disposal Building	

The control room tours included observation of parameters related to Technical Specification requirements. Alarm conditions in effect and alarms received at the control room were reviewed and discussed with the operators, who were cognizant of board conditions. Shift manning was compared with Technical Specifications. Plant housekeeping controls were observed, including control of flammable materials. Posting and control of radiation and contaminated areas were inspected. During plant tours, the various logs in the Control Room, Chemistry department, and Health Physics department were reviewed. Also, posting and attentiveness of fire watches were checked. In addition, the inspector observed selected actions concerning site security including personnel monitoring, access control, placement of physical barriers, alarm station operations, and compensatory measures. No deficiencies were identified.

2.1 PORC Meeting

The inspector attended Plant Operations Review Committee (PORC) meeting 3-86-193 on August 4, 1986. Technical Specification requirements for attendance were met. Service test procedure IST 3-86-029, a trouble-shooting test to isolate the cause of the loss of the safety injection blocking signal on July 24, was reviewed for plant impact and safety. There was a detailed discussion of the logic of significant steps to be taken in the procedure. The PORC Chairman requested explanations of circuits and test equipment arrangments from the cognizant department head. Revisions to the draft procedure were recommended; the test package was returned to the author for a 10 CFR 50.59 safety evaluation and an environmental evaluation.

The agenda also included IST 3-86-108, an in-service test procedure for steam generator water level control system operational data collection. A safety evaluation and a seismic analysis of the linear variable differential transformer (LVDT) mounts had been performed as required. The LVDTs are to be installed on the feed regulating valves under bypass jumper 386-88; a Plant Modification Request (PMR) has been written and is in progress to make the LVDTs permanent.

The final item on the agenda, a procedure change, was opened for discussion when an issue was raised that wasn't completely understood by all committee members. Time was constrained by an upcoming planning meeting. The PORC Chairman elected to reconvene PORC for a more thorough review after the planning meeting.

No deficiencies in PORC performance were observed.

3. Review of Activities Occurring During the Inspection Period

3.1 Feedwater Isolation and Reactor Trip

During the July 24 plant shutdown, a steam generator level transient at 2302 caused a Feed Water Isolation due to high level in the "C" Steam Generator. A reactor trip then occurred due to low level in the "D"

Steam Generator. The reactor had been at 16 percent power prior to the trip. Feed water flow was being transferred to the startup feed regulating valves. All equipment performed satisfactorily on the trip except that the "A" Turbine Driven Feedwater pump did not automatically trip on high level in the "C" Steam Generator. The licensee has performed a complete review of associated circuitry and hardware and has not identified the cause of the pump's failure to trip. In-service test IST 3-86-108 is to be performed during the impending startup to duplicate the scenario in an attempt to ascertain the cause of the failure to trip. The inspector will follow licensee actions in this area as part of routine inspection coverage.

3.2 Safety Injection on Loss of Block Signal

On July 25, during Emergency Diesel Generator (EDG) surveillances in preparation for a Normal Station Services Transformer (NSST) outage, an "A" train safety injection (SI) occurred at 11:47AM. The plant was in Mode 3, cooling down to Mode 5. Pressurizer pressure was below 1985 psia (P-11) and Safety Injection signals were blocked in accordance with procedure. Coincident with the start of the "A" EDG, the "A" train SI signal was momentarily unblocked, and "A" train SI equipment started. About 400 gallons of 2000 ppm borated water were injected. The primary was already borated to cold shutdown (1480 ppm). The operators recognized the spurious nature of the SI, reset the signal, and restored the lineup to normal. All SI equipment functioned as designed.

SI was unblocked twice more - once when the "A" EDG output breaker was shut and once when the "A" EDG was stopped after the surveillance was completed. In each of these cases, the reactor trip breakers were open, with the P-4 interlock in effect (automatic SI had been previously reset) so no equipment actually operated and no injection occurred

Licensee investigation revealed that the Pressurizer Pressure SI Block Reset Transfer switch in the "A" Train Transfer Cabinet had an interference at one contact. That was preventing the contact from remaining tightly closed. Two lugs were attached to the terminal above this contact, and the insulation from one was interfering with complete contact closure. The switch is a G.E. SB-9, 18 contact rotary type. The licensee was able to repeat the SI unblock when starting and stopping the "A" EDG and hypothesized that local mechanical shock from "A" EDG operation caused the contact in question to open momentarily, thereby clearing the SI block.

Immediate corrective action was to rotate the upper lug 45 degrees in relation to the lower one, providing more clearance for the insulation, and clearing the interference with the contacts. This reestablished the SI block, and the unblock could no longer be repeated. Other followup action included a complete inspection of terminations on suspect rotary switches in both transfer cabinets and diesel generator control panels, along with a 10% sample of other switches in the plant. No similar interferences were discovered.

The inspector witnessed portions of In-Service Test 3-86-029, "Data Collection for Pressurizer Pressure SI Block Signal". This test was performed to collect data to aid in the determination of the cause of the inadvertant SI. Readings taken on the 48V and 15V buses in reactor protection system logic cabinet "A" showed no voltage changes during "A" EDG start and subsequent paralleling operations. Vibration monitoring sensors were mounted on the Pressurizer Pressure SI Block Reset transfer switch to measure vibration during engine start and breaker closure. Vibration levels slightly above background were detected. Whether these low amplitude vibrations could cause momentary contact movement was indeterminant.

The problem appears to have been the high resistance at the contact on the Pressurizer Pressure SI Block Reset switch. Changing the lug arrangement reestablished the block, and duplication of the unblock could not be repeated thereafter. The inspector had no further questions.

3.3 ESF Actuation-Control Building Isolation due to Chlorine Detector Fouling

At approximately 2PM on July 24, a Control Building Isolation (CBI) occurred due to a "B" train chlorine monitor actuation signal. The CBI was determined to be spurious, so the signal was reset prior to control room pressurization. A 1-hour notification was made via the ENS. Investigation revealed a fouled probe which was replaced with a new one. There have been numerous spurious CBIs recently. New information from the chlorine probe vendor specifies that the probes be mounted vertically. The present horizontal installation allows electrolyte to wet the conductors and change sensitivity, and may be responsible for the spurious signals. The licensee is reviewing a design modification to either incorporate the vertical monitoring change or delete the chlorine monitoring system completely. (All 3 Millstone units have changed to hypochlorite anti-fouling additive for sea water systems, and there is no more chlorine stored on site.) The inspector will continue to follow progress in this area during routine inspection.

3.4 RCS Loop 2 Resistance Temperature Detector (RTD) Delayed Response Time

Measurements made for main coolant loop 2 Hot Leg temperature (Th) RTD response times were found to be in error during NSSS vendor review of the Millstone 3 Startup Report. Data taken on April 21, 1986 during the 100% power generator trip, Power Ascension Test 3-INT-8000, Appendix 8032, were interpreted incorrectly, in the non-conservative direction. Further, the acceptance criterion to which the measurements were compared was incorrect. Both of these errors are attributed to the NSSS vendor not providing up-to-date information in the Startup Manual.

The reactor engineer assumed an acceptance value of 6.0 seconds for all 4 loops, based upon the FSAR description of a 2 second transit time plus 4 seconds for RTD and electronics response. Loop 1 and 2 response times were actually measured during the test, loop 2 because of the pressurizer surge line attachment, and loop 1 to represent the remaining 3 loops. Response time was calculated by measuring the time interval between the point where neutron flux had decreased to 50% of its original value to the point where Hot leg temperature began to decrease. The measurements resulted in values of 4.0 seconds for both loops, well within the 6 second acceptance criteria.

On review of the test data, the vendor provided their accepted method of calculation of the overall RTD response time, as well as new acceptance criteria. Response times were re-calculated by measuring the time interval between the point where neutron flux had decreased to 50% of its original value and the point where the hot leg temperature had decreased by 1/3 of the initial core temperature differential. The new results were 6.7 seconds for loop 1 and 8.7 seconds for loop 2. The new acceptance criteria were 6.8 seconds for loop 1 and 8.4 seconds for loop 2. Loop 2 exceeded the acceptance limit by 0.3 seconds.

The licensee was informed of the vendor's findings on July 11, at which time the Plant Operation Review Committee (PORC) was convened to review operability and reportability requirements. PORC was informed by a vendor representative that a sensivity study completed by the vendor concluded that the additional 0.3 seconds did not change the conclusions of the Final Safety Analysis Report but that a reanalysis of the five accidents which rely on overpower and overtemperature delta-temperature trips would be required. These five accident analyses are: (1) Loss of Load; (2) Rod Withdrawal at Power; (3) RCS Depressurization; (4) Steam Line Break at Power; and (5) Steam Generator Tube Rupture. PORC concluded that, based on the information available, the protective bistables fed by the loop 2 Th RTD were operable, that the plant was not operating outside its safety analyses, and that the problem was not reportable to the NRC. PORC decided to adjourn and reconvene when the vendor transmitted a Justification for Interim Operation (JIO) with a 10 CFR 50.59 Safety Evaluation. That document arrived (Swigart to Vivano, Serial No. NEU-86-552) about 3PM on July 11 and described the vendor's review of the 5 affected safety analyses. For all but the Steam Generator Tube Rupture, the statement was made that a 2 out of 3 logic coincidence would provide the same level of protection as the 2 out of 4 logic coincidence. For the Steam Generator Tube Rupture event, the evaluation concluded only that the increase in RTD response time does not impact the conclusions of the current analysis presented in the FSAR and that no reanalysis was necessary. When PORC reconvened, it was decided that the loop 2 overpressure delta-temperature (OPDT) and overtemperature delta-temperature (OTDT) and low-low Tave protective bistables would be tripped because: (1) The Steam line break statement in the vendor document did not verify the validity of the conclusions of the FSAR; and (2) technical specifications do not address 2 out of 3 coincidence with 4 operable channels. In addition, interlock bistables C-3 and C-4 and permissive bistable P-12 were tripped. The inspector verified that, at 1825 on July 11, these 6 bistables were in fact tripped.

The inspector was concerned that the three loop 2 Th related protective bistables were not tripped before deliberations began, as soon as the safety analyses were called into question.

Additional information to support the JIO was provided by the vendor on August 6, 1986 via letter NEU-86-555 (Swigart to Viviano). That document stated that revised analysis for the steamline break concluded that the Departure from Nuclear Boiling Ratio (DNBR) design basis of 1.3 could be met provided that 1.5% of the available 9.1% generic DNBR margin could be reallocated. Paragraph 4.4.4.1 of the Safety Evaluation Report, NUREG 1031 Supplement 3, "Fuel Rod Bowing" states that the DNBR 9.1% generic margin is used to offset the worst case rod bow penalty and is not used in any other analysis. FSAR Section 4.4.2.2.5, "Effects of Rod Bow on DNBR", states that the safety analysis for the Millstone 3 core maintained sufficient margin (9.1 percent) to accomodate full and low flow DNBR penalties for rod bow. It goes on to state that the worst case DNBR penalty is less than 3%, which corresponds to a burn-up of 33,000 MWD/MTU. The inspector was concerned that margin allocation may become a problem. Since only 3% has really been allocated to rod bow, the remaining 6.1% is available; allocating 1.5% to increased loop-2 RTD response time leaves 4.6% available. The inspector discussed the margin allocation with NRR, who suggested that the licensee document the margin allocation in correspondence to the Licensing Project Manager. The licensee agreed to do so.

As a result of their review of vendor supplied information in the JIO, the licensee had decided that the 6 tripped bistables fed from the loop-2 Th RTD could be reset and did so. The inspector had no further questions.

3.5 Loss of Fourth Point Heater Drain Pumps

The plant was in routine full power operation on July 21 when, at 0706, each of the three running fourth point heater drain pumps tripped due to low heater level. The loss of these pumps resulted in a reduction in the amount of water available to the feed pumps. Condensate demineralizer differential pressure went high with increased condensate demand. The "B" Turbine Driven Feedwater Pump, one of the two running pumps, tripped at 0708 due to low suction pressure. Control room operators started the Motor Driven Feedwater Pump and also began to reduce turbine load. Manual control was taken of the steam generators and boration of the primary was initiated. Reactor rod control remained in automatic. Reactor power was reduced, and was stabilized at about 80 percent.

The inspector observed licensee personnel actions in the control room. Prior to the transient, day shift operators had reported to the control room and were reviewing the main control boards. Personnel reacted quickly to the loss of the heater drain pumps and monitored heater level, attempted to bypass the condensate demineralizers, restored full feedwater flow, and stabilized steam generator levels. The event was complicated by the fact that the condensate demineralizer bypass valve motor operator breaker tripped on overload when operated. This was probably due to the high differential pressure across that valve. The inspector observed that, although most of the day shift operators had reported to the control room and various licensee management personnel were conducting control room reviews, the off-going Shift Supervisor remained in control. Extra persons were directed to give specific assistance, and a clear path of authority remained uninterrupted. Control room operators reacted quickly and in a positive manner in stabilizing steam generator levels.

Licensee investigation revealed that the loss of heater level was caused by the removal of a single 10 amp fuse in a 125V DC supply. Loss of power in that single load circuit caused all normal level control valves to shut and all emergency level control valves to open. All heater drain flow was directed to the condenser hotwell instead of cascading to the fourth point heaters and the drain pump suctions. Power was restored to the control circuit, heater levels were re-established, and the drain pumps were started at about 1615. The reactor was restored to full power at about 2230, July 21.

The fuse in question had been removed from the panel (3BYS-PNL 31F, Circuit 2) to allow work on an auxiliary condensate valve (3CNA-AOV 48, Condensate to Auxiliary Condensate Divert Valve). That action was taken in accordance with an approved work authorization. However, the personnel involved failed to realize that the same circuit also supplied power to all normal and emergency level control valves for all three strings of the first, second, third and fourth point feedwater heaters and also the level control valves for both moisture separator reheater steam drain tanks.

The inspector reviewed the circumstances concerning this error and found that on the "one-line" diagram of Battery No. 6, panel 31F Circuit 02 is designated "Condensate to Condensate Divert Valve 3CNA-AOV 48, ESK-7RX, 7A, 7B, 7C, and 7BV" (Drawing 25212-30108 Sheet 1, S&W No. 12179-EE-1BT-14). If the referenced ESK drawings are reviewed, the elementary circuit-diagram for valves 3CNA-AOV 40 and 3 CNA-AOV 48 are found on 12179 ESK-7RX (25212-32088). However, other references show that this circuit also powers all heater level control valves (12179-ESK-7A, 7B, 7C and 7BV). The inspector found that the labelling for panel 31F, circuit 02 on Drawing 25212-30108 Sheet 1 was deceiving, and that drawing 25212-32533, 12179-ESK-7BV failed to identify the source of power for the moisture separator reheater drain tank level control valves. In order to prevent recurrence, these drawings need to be upgraded. Additionally, the inspector concluded that plant personnel should be instructed on the need to more throughly research plant design data in circumstances such as this. There were no violations and no other deficient conditions identified. The heater drain system is not safety-related. However, failures within the system may result in a challenge to safety equipment and may result in an unnecessary reactor trip. Licensee action on this consideration will be reviewed during routine inspection.

3.6 Investigation of RCS Leakage Calculation

At 0443, July 23, the licensee began to investigate unidentified reactor coolant system leakage calculated in excess of one gallon per minute. The source was found within the chemical and volume control system. A three-way valve which diverts letdown flow to the liquid radioactive waste system was found to be leaking internally, allowing some flow to radwaste instead of to the volume control tank. The problem was identified when a manual isolation valve was shut.

The inspector found that the computer program which calculated reactor coolant system leakage assumes no flow to the radioactive waste system if the divert valve is positioned in the volume control tank. The existing conditions were found to be conservative in regard to nuclear safety. There were no unacceptable conditions identified.

3.7 Termination of Shift Advisors

NRR approved the licensee's elimination of shift advisors from the control room staff on July 15, 1986. A condition of the Millstone Unit 3 Operating License (NPF-49) requires that there be a senior licensed operator on each shift who has had at least 6 months of hot operation experience on a plant of similar design, including at least 6 weeks above 20% power along with startup and shutdown experience. This license condition authorized use of shift advisors to provide the requisite operating experience; the licensee had utilized 3 such advisors since initial criticality. On July 15, when the unit had sufficient operating history to provide the hot operating, shutdown, and startup experience to satisfy the license condition, the advisors were terminated. The inspector had no questions on this item.

3.8 Plastic Contamination of 316 Stainless Steel Pipe

Before this inspection period, licensee personnel had discovered melted plastic and tape on the Reactor Vessel Head Vent line and generated Unsat 7421 on January 4, 1986. The head vent line is a 1" outside diameter, type 316 stainless steel pipe connecting the head vent valves to the pressurizer relief tank. Evidently, sections of the line (pipes 3RCS-003-70-1 and 3RCS-001-228-02) had been cleaned in preparation for insulation, wrapped with an approved protective covering and tape to prevent re-contamination, but were never insulated. The covering melted to the pipe during hot functional testing. Resolution of the Unsat was deferred since it was not considered significant or generic. Cleaning of the pipe was began, but cleanup of poorly accessible sections was deferred due to time constraints.

The materials involved were approved for use on category I systems. The plastic was Loretex 3000 FR-7 flame retardant reinforced polyethylene supplied under Stone & Webster specification 2199.170-915, Revision 3. Laboratory analysis for leachable chlorides was performed in accordance with ASTM D512-1981, requiring 1 hour reflux of the plastic in demineralized water, and showed 27.1 ppm and 28.2 ppm in batches delivered. Laboratory analysis of the Polyken No. 226 white cloth tape, supplied under the same Stone and Webster specification showed leachable chlorides of 2 ppm, fluorides less than 1 ppm and total halogens between 32 and 44 ppm.

The inspector reviewed Automated Work Order 3-86-12987 for the pipe cleanup. The procedure mandated Administrative Control Procedure (ACP) QA-4.01A and ANSI N45.2.1 for cleanliness control, and required final halogen swipe tests and dye penetrants testing when residue removal was complete. A high speed large diameter stainless steel wire brush was used to clean the pipe.

The inspector was concerned that a chemical transformation of the polyethelylene may have occurred during the melting process and that excess halogens might be released to the pipe surface. The licensee had performed an analysis using the reflux technique of ASTM D512-1981 on a sample of the melted plastic and found 0.148 mg/dm2 Chloride. The Westinghouse limit on uninsulated pipe is 0.15 mg/dm2 chloride and 0.037 mg/dm2 fluoride. However, while the measurements were taken with an ion chromatograph (+/- 2 ppb), the sampling technique and control were questionable, making the results questionable.

Because of the uncertainty of the chemical properties of melted plastic and tape, the licensee decided to completely clean the pipe and did so on August 9. Final swipes showed 0.005 mg Cl/dm2 and 0.0013 mgFl/dm2. Dye penetrant testing found 2 relevant indications on cast tees. Both were evaluated as acceptable. There were no cracks. A licensee inspection found that this was the last of this residue in containment. The inspector had no further questions.

3.9 Main Steam Safety Valve Blowdown Ring Adjustment

As a result of a commitment made in the licensee's May 2, 1986 response letter (MP-3-516) to IE Notice 86-05, "Main Steam Safety Valve Tests Failure and Ring Setting Adjustments", automated work order M3-86-08574 was generated to inspect the 5 spare Dresser steam generator safety valves. Inspections completed on May 28 showed that all 5 valves had improper blowdown ring settings.

The licensee reviewed vendor procedures to determine the reason for the improper ring settings. It was found that the original procedure provided to the architect/engineer for purchasing QA did include the ring setting instructions. However, the revision to that valve assembly procedure under which the Unit 3 valves had been assembled had the ring setting instructions deleted. Further, it was discovered that the vendor functional steam testing procedure allowed setting the rings to zero to minimize blowdown, thereby conserving steam pressure from their low capacity boiler. Additionally, none of the vendor procedures or Stone and Webster QA field inspection reports reviewed by the licensee contained any hold points for ring settings. The ring settings on the installed steam generator safeties were therefore questionable.

During the unplanned outage, all 20 steam generator safety valves were inspected for blowdown ring settings. Every valve was improperly set and no two valves were the same. Moreover, the ring pins on 3 of the valves (MSS-RV-25B, 22C, and 26C) were too short to engage the ring notches. The rings were reset to +160 notches on the upper rings and -8 notches on the lower rings. The three short pins were replaced and all 40 pins were lockwired. Work was completed on July 29 under automated work orders M3-86-08578, 08579, 08580, and 08581.

The safety significance of incorrect blowdown ring settings is that, as both rings approach zero settings, blowdown approaches zero and the valve will reseat immediately after lifting. Such valve chatter might damage the disc and seat and could affect the design relief capacity. As the upper and lower ring settings approach maximum, blowdown becomes extreme and the valve will reset significantly below its lift pressure. This would cause excessive cooldown and might result in excessive releases during a steam generator tube rupture. The effect of a short ring pin is that the blowdown ring might reposition during valve operation, resulting in variable blowdown settings.

The root cause of these improper settings appears to be with the vendor fabrication procedures and quality control. The licensee is compiling information for a 30 day notification to NRC. The inspector had no further questions.

3.10 Interactions Between Seismic Class I Components

The licensee discovered on May 20 that the Number 3 Battery Charger, associated with 125 volt Battery 301A-2, had insufficient seismic shake space between it and 120 volt a.c. Vital Bus Number VIAC-3. Although both components remained in service, the Battery Charger was considered to be inoperable under Technical Specification Limiting Condition for Operation (LCO) 3.8.2.1.b. The LCO action statement concerning 120 volt a.c. Vital Bus Number VIAC-3 was met as the bus was energized as required. The licensee temporarily corrected the deficiency by banding the two cabinets together, causing them to act as a single seismic structure. This corrective action had been found acceptable by licensee engineering analysis. The problem, inadequate shake space, had existed during construction. Corrective action has been implemented for the other three Battery Chargers by moving the static inverters.

During the current outage, the inspector observed the relocation of Number 3 inverter 1 inch away from Vital Bus number VIAC-3. Welding procedures were reviewed and equipment protection from welding process environment was verified. There were no unacceptable conditions identified.

3.11 Snubber Inspections

Technical Specification surveillance requirement 4.7.10 calls for performance the first in-service visual inspection of all snubbers after 4 months but within 10 months of commencing power operations. The licensee elected to perform the surveillance during the unplanned outage which commenced on July 24. Inspections were performed under surveillance procedure SP 37125, Rev. 0 dated July 29, 1986. Acceptance criteria conformed to the requirements of technical specification surveillance 4.7.10.c, "Visual Acceptance Criteria." Actual inspection procedural steps were referenced to Northeast Utilities Service Company NDE Procedure NU-VT-1, "Procedure for Inservice Visual Examination", Rev. 4, dated 3/22/84, Appendix F for hydraulic snubbers and G for mechanical snubbers. NU-VT-1 Appendices F and G comply with the visual examination requirements of ASME Section V Article 9 and Section XI, 1980 edition through Winter 1980 Addenda.

All 1184 snubbers in the plant were visually inspected; 923 met the acceptance criteria with no evaluation required; 261 needed evaluations of observed deficiencies. These evaluations were made in accordance with step 7.2 of SP37125, using Maintenance Forms 37125-3 through 37125-6. All but 44 of these 262 snubbers required only trivial evaluations to be found acceptable. The 44 in question were determined to need functional testing due mainly to boric acid contamination. The licensee elected to replace all 44 questionable snubbers. The inspector witnessed a sample of the functional testing of the replacement units in accordance with Technical Specification 4.7.10. No unacceptable conditions were identified.

Of the 44 snubbers that were removed and functionally tested, 29 met the acceptance criteria with no further evaluation. In these cases, the licensee's drag limit of 5% was not exceeded. Of the remaining 15 units, 1 was locked-up and 14 exceeded the 5% drag limit. The functional test data showed that 8 of these 14 had drag spikes outside the operating range of the unit. For snubber and system operability, the existence of the drag spike outside the operating range was deemed to be satisfactory. The remaining 6 units exceeding 5% drag and the locked-up unit required system stress analysis to determine system operability. The inspector reviewed calculation packages that analyzed pipe stresses resulting from increased drag from the locked-up snubber and 4 of the remaining 6 snubbers and found no deficiencies.

As a result of the stress analyses, the licensee concluded that all systems supported by the 15 questionable snubbers had remained operable. The locked-up snubber was declared inoperable, which modifies the subsequent visual inspection period of Technical Specification 4.7.10.b to 12 months +/- 25%.

A snubber specialist contractor will be on site within the next 2 weeks to disassemble and inspect the removed snubbers to determine the causes of drag forces exceeding 5% and collect data to assist the licensee in defining the drag force operability threshold.

Installed snubbers were not functionally tested by the architect/engineer, who depended on vendor test documentation and freedom of motion tests performed in the field prior to installation. The inspector questioned whether the 15/44 (34%) rate of elevated analysis or 1/44 (2.3%) rate of failure might be only coincidental with boric acid contamination and therefore attributable to the entire population of snubbers. Licensee engineers stated that visual examination and manual freedom of motion tests, along with documented vendor test results, provide sufficient assurance of operability.

There were no violations of NRC requirements. The inspector will continue to follow the licensee's analysis of snubber operability during routine inspection.

3.12 Damage to Relief Valve CHS-RV-8117

During performance of operations department surveillance SP3646A.9, "Slave Relay Test Train B", which is a "go" type operability test, 600 psi letdown relief valve CHS-RV-8117 was inadvertantly lifted with full RCS pressure. Considerable nozzle and disc damage resulted, preventing the valve from fully reseating and causing an 11 to 15 gpm identified leak rate from the reactor coolant system (RCS). This leak rate exceeded the technical specification limit of 10 gpm, and the plant was taken to cold shutdown to repair the valve. All leakage was to installed tankage; there was no radiation release or spread of contamination.

The relief valve is between the two containment isolation valves, CHS*CV8160 (inboard) and CHS*CV8152 (outboard), and downstream of the 3 letdown orifices. Step 7.18 of SP3646A.9 tested the slave relay, thereby shutting CHS*CV8152 while the letdown system was operating, allowing full RCS pressure to lift RV8117. The inspector reviewed the procedure and found it did not contain a specific warning that this overpressure would occur, only that letdown would be isolated. There was no indication that the procedure had not been properly followed. The licensee generated a plant incident report and has the event under review. A procedure change to have letdown isolated at the orifices is being considered, since the surveillance does not require valve stroke against full flow. The inspector will follow the licensee's progress on this item during routine inspection.

4. Observation of Maintenance

The inspector observed and reviewed preventive and corrective maintenance to verify compliance with regulations, use of administrative and maintenance prodedures, compliance with codes and standards, proper QA/QC involvement, use of bypass jumpers and safety tags, personnel protection, and equipment alignment and retest. The following activities were included:

-- Main Steam Safety Valve Blowdown Ring Inspections
-- Relocation of Battery Charger Number 3
-- Repair of Main Generator Phase Neutral High Voltage Bushing
-- Removal of Turbine Valve Protective Screens
-- Functional Testing of Mechanical Snubbers
-- Repair of Letdown Relief Valve CHS RV 8117
-- Refurbishment of Main Feed Pump Recirculation Control Valve Bodies
-- Vibration Testing of "A" Train Transfer Switch Cabinet
-- Placement of various fire seals in SLCRS Boundary

5. Observation of Surveillance Testing

The inspector observed parts of tests to assess performance in accordance with approved procedures and Limiting Conditions of Operation, removal and restoration of equipment, and deficiency review and resolution. The following tests were reviewed:

-- SP3443B21, Protection Set Cabinet 2 Operational Test
-- "A" & "B" EDG Operability Tests
-- SP3440A01, Plant Startup Surveillance (portions)

No unacceptable conditions were identified.

6. Review of Licensee Event Reports (LERs)

LERs submitted during this report period were reviewed. The inspector assessed LER accuracy, whether further information was required, if there were generic implications, adequacy of corrective actions, and compliance with the reporting requirements of 10CFR 50.73 and Administrative Control Procedure ACP-QA-10.09. Selected corrective actions were checked for thoroughness and implementation.

Those LERs reviewed were:

-- 86-036-00, Violation of Plant Technical Specifications: Non compliance with action statement 3.8.2.1.b (see item 3.10).

   This is a violation of NRC requirements. A notice of violation has not been issued since the problem was licensee identified, immediately communicated to the inspector, and acceptable corrective action was quickly implemented.

-- 86-037-00, CBI Signal from Chlorine Detector A train.

Item 3.3 describes a recurrence of this problem with planned corrective actions.

7. Reporting Requirements Review

Recently, the NRC Incident Response Branch (IRB) asked Region I to review NNECo's classification of events reportable under 10 CFR 50.72 as "general interest". Also, during preparation of the recent Systematic Assessment of Licensee Performance (SALP) for Millstone, Units 1 and 2, licensee assignment of cause codes for equipment failure and overall event cause statements for Licensee Event Reports (LERs) had been questioned. These two issues were inspected during the week of July 14, 1986. Licensee personnel contacted showed interest in improving Emergency Notification System (ENS) reports and LERs.

7.1 Event Classification

The inspector reviewed three Unit 1, one Unit 2, and nine Unit 3 events that were classified by the respective unit control rooms as "general interest." The inspector also reviewed the controlling procedures (EPIPs 4112 and 4701) and had discussions with shift supervisors and plant management. The term "General Interest Event" appears under the Incident Class column on the first page of EPIP Form 4112-1 (Incident Reporting Document). This form's Incident Classes, (e.g., Unusual Event, Site Area Emergency, General Emergency) are generally NRC terms. State of Connecticut terms (ALPHA, BRAVO, ..., GOLF) generally correspond to the NRC terms in the adjacent column, but the ECHO term, "General Interest Event" applies only to the State of Connecticut. Since 10 CFR 50.72(b)(2)(vi) (Non-Emergency Events/Four-Hour Reports) requires reporting any event or situation for which notification to other government agencies has been or will be made, everything reported to the State is also reported to the NRC. Thus, the licensee's "general interest" reports were not required by 10 CFR 50.72 because of safety significance but were reportable to the State and, therefore, to the NRC.

It was also noted that the State of Connecticut requires that all reports of events be made within one hour. Many NRC reports are due within four hours. The licensee, to eliminate confusion, makes all reports within one hour.

The inspector found no violation or safety inadequacy in the licensee's ENS reporting.

7.2 Event Cause Codes

The inspector discussed preparation, review, and approval of LERs with unit LER Coordinators and with responsible management.

A clear understanding of the LER form, including cause codes, was found to be held by the plant staff. However, some of the Unit 3 staff were assigning failure cause codes for LERs not involving failures of equipment. In addition, some of the LERs reviewed had no clear text statement regarding the overall cause of the reported event. The inspector conveyed to the licensee's staff that NUREG 1022 guidance to fill in the cause code blocks only for component failures still holds. If there is no equipment failure, the cause code blocks should be left blank. An overall cause code, which may differ from the assigned equipment failure cause code, should be assigned in the LER text.

Although room for improvement was noted, the inspector found no significant inadequacy in the licensee's LERs.

8. Status of Previously Identified Items

(Closed) 76-CI-03, Radiation Exposure in Reactor Cavities The inspector verified the installation of lockable gates at all entrances to the Moveable Incore Detector (MID) area. This item is closed.

9. Management Meetings

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