U.S. NUCLEAR REGULATORY COMMISSION
REGION I

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Approved by: for Paul Swetland, Team Manager, Projects Branch 4 — 3/5/93 Date

Scope: The OSTI was tasked with a number of technical and operational performance areas to observe and review that were of interest to the NRC during the restart of Unit 2. In particular, the team reviewed the completion of operations, surveillance, maintenance and engineering/technical support activities. The team also observed the conduct of the restart as well as assessed NU's overall performance during these evolutions. Sections 1.2 and 1.3 of this report further describe the scope of this report. The findings of the team are summarized in Section 5 of this report.

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1. INTRODUCTION/PURPOSE OF OPERATIONAL SAFETY TEAM INSPECTION

1.1 Background

In the most recent Systematic Assessment of Licensee Performance (SALP) 90-99 covering the period from December 16, 1990 to February 15, 1992, the NRC noted performance declines at all three Millstone units. In particular, problems were experienced at Millstone Unit 2 with the erosion/corrosion program, steam generator tube leakage, emergency diesel generator operability and configuration control that indicated a decline in performance. In response to this observed decline in performance, the NRC established a Millstone Assessment Panel (MAP) to assist Region I and NRR in the coordination of NRC resources for performance monitoring, inspection planning, and assessment of Millstone Station activities. Due to the extensive scope of the Unit 2 refueling and steam generator replacement outage and the performance concerns that existed, the MAP elected to send a team of NRC inspectors to observe the preparations for heat-up and the restart of Millstone Unit 2.

1.2 Unit 2 Outage Scope

The Cycle 11-12 outage at Millstone Unit 2 commenced on May 29, 1992 and was originally scheduled to end in mid-October. The outage ultimately was extended until early January 1993 due to several significant technical problems that were identified early in the outage and are discussed below. During the outage, the reactor core was fully off-loaded from the reactor and transferred to the spent fuel pool to facilitate the replacement of the plant's two steam generators. Each of the steam generators was cut from the reactor coolant system, the steam drum of each steam generator was cut at the girth weld, and both lower sections were removed from the containment building and shipped to a waste disposal site for burial. Due to an unexpected movement of the reactor coolant system piping following cutting, extensive analysis was conducted shortly after rewelding the pipes to the steam generators. The NRC's review of Northeast Utilities' (NU - the title used throughout the report for simplicity to identify both NNECO, the licensee for Unit 2 and NUSCO, the engineering services organization for Millstone and Haddam Neck) analysis is described in Attachment 1 to this report. The new steam generators were lifted into the containment building, the steam drums were reworked and rewelded to the new steam generators and the reactor coolant system piping was rewelded to the steam generators. The reactor core was then reloaded with some the reactor fuel assemblies replaced with new fuel assemblies.

During the outage, NU also performed a number of other testing activities as well as significant plant modifications, including modifications to ensure the isolation of feedwater to the steam generators in the event of a main steam line break inside containment. This concern was identified during the analysis to support the replacement of the steam generators and was necessary to ensure that the continued addition of feedwater would not cause the containment building to be overpressurized during such an event. In addition to the modifications that NU originally had scheduled, a modification to the logic circuitry to deal with a loss of normal power was made due to design weaknesses identified during an event on July 6, 1992.

1.3 Scope of OSTI Review

In order to observe NU's performance during the restart, a team of inspectors was dispatched to the site for the period between December 28, 1992, and January 14, 1993. The team observed preparations for the heat-up of the unit, the completion and satisfactory testing of significant plant modifications, the resolution of specific outstanding technical concerns and the restart of the plant. The scope of the review is discussed in the body of this report and is consistent with the charter provided the team by the MAP (see Attachment 2). The inspection scope was comprehensive of the critical restart activities ongoing and involved the work of nine inspectors, the majority of whom were familiar with Unit 2 plant operations. The inspection included a round-the-clock coverage from prior to the heat-up of the plant through the start-up of the reactor five days later. The overall findings and conclusions of the team are discussed in Section 5 of this report.

2. COMPLETION OF OPERATIONS/SURVEILLANCE/MAINTENANCE ACTIVITIES IN SUPPORT OF PLANT RESTART

2.1 Configuration Control

The team reviewed the safety system valve lineups required for Mode 4 operations. An independent verification of valve positions for containment integrity was performed; all valves inspected were in their required locked-closed positions. The team also reviewed NU's previous corrective actions for a non-cited violation involving the failure to complete the surveillance of specific valves when plant conditions prevented the verification of normal lineups. The team verified that NU was properly tracking those valves that could not be aligned due to existing plant conditions. These included, for example, containment integrity valves for containment fire header isolation and containment station air isolation. NU's outage control personnel in charge of surveillance testing ensured that the heat-up checklist items were not signed off until the surveillance was entirely complete. The team also accompanied operators performing valve lineups. During the performance of procedure 2604E-2, "High Pressure Safety Injection System Valve Alignment, Facility 1," the team noted that the second checker did not know how to check the position of a locked valve. NU procedures specify that the position of a locked valve be verified by a position indicator or by a rising stem. The team found that all the valves that were checked were in their required position. However, since the individual performing the valve lineup was unaware of the correct method of verifying the position of locked valves (although the method was described in an Operations procedure), he attempted to operate a valve with the locking device installed, breaking the locking device. The team concluded that this area warrants some refresher training.

A violation (92-04-01) was previously issued in early 1992 involving the failure to have an operable high pressure safety injection (HPSI) system prior to entry into Modes 3 & 4 from Mode 5. The inspector reviewed the implementation of NU's corrective actions to ensure that they had proper configuration control of the HPSI system prior to heat-up. During the current preparations for heat-up, the HPSI system alignment verification (procedure 2604E-2) was only partially completed in that facility 1 header isolation valve 2-SI-656 was closed rather than locked open (plant conditions at the time did not require an operable train of HPSI). The team verified that this situation was properly handled; specifically, that the heat-up checklist for this surveillance was not signed off as complete, operators and the outage control group were aware that this valve remained to be aligned and that its status was being properly maintained, and the plant heat-up procedure was also revised to add the necessary steps to ensure that one train of HPSI was operable prior to changing modes. Prior to commencing plant heat-up, NU locked open the valve to provide the required operable HPSI train.

Overall, the team concluded that NU had proper configuration control of the systems required for Mode 4 operation (although there were several other observations in this area documented in NRC inspection report 92-31 indicated that configuration lapses did occur. The heat-up checklist used by the outage control group was well utilized as a tool for configuration control.

2.2 Plant Housekeeping

During walkdowns of the Unit 2 auxiliary building about 1 week prior to plant heat-up, the inspectors noted that general housekeeping and cleanliness was poor. In particular, the east and west penetration rooms (38.6 feet elevation) contained large amounts of general debris, plastic wrap, rags, and broken glass. NU was in the process of cleaning up the auxiliary building, but had not yet commenced cleaning in the aforementioned rooms. Subsequent inspections of these areas by the team indicated some improvement.

An extensive tour of the Unit 2 containment building was conducted four days prior to plant heat-up by the team with an Operations representative. The tour indicated that while NU had expended a considerable amount of effort to clean-up the containment following the outage, at least 1-2 days of additional cleanup work remained to be completed prior to heat-up. All deficiencies noted were reported to Operations management for resolution; resolution of these deficiencies was subsequently confirmed by NU management tours of the containment.

The team performed a general tour of containment after plant heat-up and noted that general housekeeping and cleanliness was very good with the exception of the area around the access point. The team attributed this to transient debris and ongoing feedwater support work in the area.

2.3 Surveillance Testing Status

The team performed a review of the Operations department heat-up checklist (OP 2201-1) to ensure safety systems were properly restored to operability. The team compared the Unit 2 technical specifications to the checklist and verified that all equipment required to be operable for Mode 4 was annotated on the checklist with their respective surveillance tests. A review of completed surveillances was also accomplished by the team. These included surveillances for reactor building component cooling water, service water, safety injection tanks, charging pumps, primary containment, emergency diesel generators, and high pressure safety injection pumps. The acceptance criteria for these surveillances were satisfied, and the tests were completed within the required time interval to support plant heat-up. Refueling/18 month technical specification surveillances were also properly tracked and completed to support plant heat-up. Overall, the team found that the outage control group maintained positive control over these surveillances for system configuration prior to mode changes.

2.4 Status of Equipment Maintenance

The team reviewed NU's list of all outstanding maintenance and retest activities necessary to support plant heat-up. The team noted that NU lacked an integrated schedule to coordinate maintenance, retest, valve lineups and surveillance testing on each individual safety system; coordination of these activities is accomplished informally at two daily planning meetings. As a backup method, the Operations department determines if there are any safety tags on a particular stem to determine if there are any outstanding maintenance activities. However, the team was concerned that outstanding maintenance and retest activities had the potential to adversely impact plant safety and may not have been detected by NU's informal process for coordinating these activities. They did note during the observation of a surveillance test that NU had not calibrated the position indicator for two feedwater valves, 2-FW-41 A/B, and that there were outstanding maintenance items to perform the calibrations. However, in this case, the surveillance would not have been invalidated due to the missed calibration. No actual safety impact was noted due to NU's good informal communications between departments.

Subsequent discussions with NU indicated that they had recognized the weaknesses in the work control process and are planning a major upgrade to this process in 1993 as part of the Performance Enhancement Program (PEP). NU plans to establish an Integrated Team that will plan, coordinate, schedule, and status all plant work. NU also plans to establish a Station Planning Director who will report directly to the Station Vice President and will optimize planning activities for refueling outages, as well as day-to-day activities. The

Integrated Team will consist of planners and personnel from the Operations, Maintenance and Instrumentation and Controls departments. The Integrated Team will determine work priorities and approve an integrated schedule on an ongoing basis. The team viewed these changes as a positive step toward improvement.

2.5 Bypass Jumper Controls

The team reviewed NU's jumper, lifted lead, and bypass control log book prior to Mode 4 plant operations. The team noted that two temporary modifications were open that required closeout prior to plant heat-up. Jumper device 2-92-197/198 involved the use of electrical jumpers for the low temperature overpressure protection (LTOP) system. The jumpers maintained the LTOP system "enabled" with reactor coolant system (RCS) temperature less than 275°F. The RCS loop resistance thermocouple detectors (RTDs) normally provide input to LTOP, but were replaced during the current outage and were not yet fully operational. The team found that NU was appropriately tracking this jumper device for LTOP restoration prior to heat-up. The team subsequently verified that these jumper devices were removed following cold calibration of the loop RTDs. Another jumper device (2-92-160) involved the use of temporary shielding around the recovery boric acid storage tanks (RBAST). The shielding installation was originally restricted to Mode 5 and 6 operations. However, on January 4, these restrictions were removed following PORC approval. The team reviewed NU's basis for removing the mode restrictions and agreed that the temporary shielding could remain for plant operations. On January 3, NU added a new jumper device for the reactor vessel level indication system (RVLIS). This system consists of two channels with eight thermocouple probes per channel to sense water level; NU jumpered out two faulty thermocouples from channel 'A'. The team reviewed the associated safety analysis and found this action to be acceptable and did not involve an unreviewed safety question. Technical Specification 3.3.3.8, "Accident Monitoring," requires a minimum of one channel operable with a minimum of four sensors for Mode 1, 2, and 3 operations. Adequate reactor vessel level monitoring is available from both channels.

Overall, NU had proper control of jumpers and lifted leads prior to plant heat-up. The team verified that NU was satisfactorily tracking Mode 4 jumper restrictions and that those installations that remained were compatible with plant conditions that would exist following the mode change. Additionally, NU had satisfactory technical justification for either leaving the temporary modifications in place or adding the additional jumper devices.

2.6 Reactor Operator Overtime Usage/Refresher Training

The team reviewed the overtime usage by operators to ensure consistency with the guidance of Generic Letter 82-12, "Nuclear Power Plant Staff Working Hours." The overtime usage for senior reactor operators in the two outage crews and four shift crews was reviewed. The team noted a high use of overtime for the outage crews for the months of November and December. Over 60 hours of work, excluding shift turnover time and duty as the Director-Station Engineering Operations (DSEO), was common for many SROs. In fact, commencing December 26, the outage crews began working 10 hours per day seven days a week (70 hrs/week) in order to support plant heat-up. This amount of overtime is, however, within the guidance of the generic letter that allows up to 72 hours in any 7 day period during extended periods of shutdown. Deviations from this guidance were authorized and documented by the plant manager on several occasions. Operator performance during the team's inspection did not indicate any performance problems due to fatigue.

The team noted during their review that three individuals received authorizations to exceed established overtime limits by plant management after the individuals had already exceeded the working hour guidelines. While these incidents occurred early in the outage before NU adopted a better time tracking system, additional management attention in this area may be warranted to ensure deviations are approved prior to exceeding the working hour guidelines so that an individual's physical condition can be properly evaluated and management can consider options other than the extraordinary working hours. The team was informed that as part of the Performance Enhancement Program, NU is hiring six additional SROs to augment Operations department staffing. Overall, except for the exceptions noted above, the team concluded that NU was meeting the intent of Generic Letter 82-12 and that their administrative controls for overtime usage and authorization were adequate. The hiring of additional operators is considered a good step towards reducing the Operations workload and the reliance on overtime.

To evaluate the readiness of the reactor operators to restart the reactor, the NRC conducted inspection 50-336/92-33. During that inspection, the NRC reviewed operator refresher training in preparation for reactor start-up, training on plant design changes and other operator performance related issues. The team spent some additional time looking at operator training on modifications made during the outage. This subject is discussed in detail in inspection report 92-33; the team's findings substantiate the findings made during that inspection regarding operator training on modifications (the team's observations of overall operator performance are discussed Sections 4 and 5 of this report).

2.7 (CLOSED) LER 90-020-00 - Missed Service Water Surveillance (UNR 50-336/91-01-04) and Failure to Perform Post-Maintenance Testing (OI 50-336/91-04-02)

The team reviewed the status of two open inspection findings at Unit 2 due to their applicability to the activities supporting the restart of the unit. Licensee Event Report 90-020-00, reported a missed surveillance that occurred in February 1990, when the line-up of three service water system valves could not be verified, as required in the surveillance procedure, due to ongoing maintenance activities. As described in the LER, the surveillance remained open until after the surveillance interval had elapsed, making the occurrence reportable. Secondly, NU identified in March 1991 that a charging system valve, CH-198, had been returned to service without completion of a required post-maintenance test. The NRC in Inspection Report 50-336/91-04 identified an open item to follow-up NU activities to return plant systems to service following maintenance.

To follow-up these items, the team reviewed the following surveillance procedures completed to restore the various safety related systems to operability following the steam generator replacement outage:

- SP-2612C/D - Service Water, Facility 1/2
- SP-2604E/F - HPSI Valve Alignment, Facility 1/2
- SP-2604L/M - LPSI Valve Alignment, Facility 1/2
- SP-2605A - Containment Integrity Valve Alignment
- SP-2605H - Containment Isolation Operability Test
- SP-21131 - Type C, Local Leak Rate Testing (2-CH-198)

In reviewing the testing, the team verified that the proper procedure was used in conducting the surveillance, data sheets were properly completed and reviewed, the surveillances were completed when required to complete the plant heat-up checklist (Operations Form 2201), and double verifications of safety system valve positions were completed as administratively required by NU following a cold shutdown outage.

All of the surveillance tests had been completed in accordance with station administrative procedures. Procedure revisions due to on-going maintenance were approved in accordance with 2-OPS-1.14, "Equipment and System Alignments." While no deficiencies were identified during this review, NU subsequently issued a Problem Identification Report (PIR) on an additional problem with post-maintenance testing similar to that identified in open item 91-04-02. Since the follow-up on that issue will be addressed in inspection report 92-35, this open item as well as unresolved item 91-01-04 are considered closed.

2.8 Thermo-Lag Compensatory Measures

Nuclear plant licensees were informed in July 1992 of potential problems with the qualification of Thermo-Lag fire barrier materials by NRC Bulletin 92-01, "Failure of Thermo-Lag 330 Fire Barrier System to Perform its Specified Fire Endurance Function." At that time, Unit 2 was in the steam generator replacement outage and was defueled; therefore, no compensatory measures were required for existing Thermo-Lag material.

Prior to entry into operational mode 4 (in which safety systems are required to be operable), the team verified that Unit 2 had taken the appropriate compensatory measures for already existing Thermo-Lag materials. By letter dated October 1, 1992, NU responded to Supplement 1 of Bulletin 92-01 and informed the NRC of specific measures to be established for the Millstone and Haddam Neck sites. Attachment 2 to that letter tabulates the Unit 2 fire zones protected by Thermo-Lag and NU's planned compensatory measures. The team verified that there were seven hourly fire patrols and one continuous fire watch established prior to entry into operational mode 4. The team noted that these fire watches had been initiated on November 22, 1992, prior to reactor core reload.

2.9. Plant Design Change Completion

The team reviewed plant design change records (PDCRs) to determine the completion status as it relates to readiness for plant restart. The team paid particular attention to the completion of the requirements for system operation as described in step 4.14 of administrative control procedure (ACP) ACP-QA-3.10, "Preparation, Review, and Disposition of Plant Design Change Records (NEO 3.03)." In addition, the team reviewed NU's use of design change notices (DCNs) to PDCRs to verify that DCNs were processed in accordance with procedures ACP-QA-3.10 and ACP-QA-3.14, "Design Change Notices for Design Documents (NEO 5.11)." The following PDCRs were included in this review:

- PDCR 2-007-88 Auxiliary Feedwater System Steam Bypass Line
- PDCR 2-014-91 Shutdown Cooling System Auto-Closure Interlock Deletion
- PDCR 2-152-92 ESAS ATI Test Window Modification/SRAS Logic Modification
- PDCR 2-078-92 RPS Pressurizer Pressure Alarm Modification
- PDCR 2-071-92 MP2 Diesel Control System Modification
- PDCR 2-028-92 Containment Pressure Signal Addition to MSI Function
- PDCR 2-114-92 Required Modifications for Main Steam Line Break Scenario
- PDCR 2-007-92 Station Battery Charger 201B Replacement
- PDCR 2-123-91 DC/AC Inverter Replacement
- PDCR 2-204-92* F15 'A' Flow Diverter from 'A' Room to 'C' (Swing) Room
- PDCR 2-013-91* Service Water Temperature Indicator Replacement
- PDCR 2-056-90* X-18A, B & C Excess Drain Piping and Hanger Removal
- PDCR 2-069-92* X-18A, B & C Excess Drain Piping and Hanger Removal (Brass)
- PDCR 2-178-92* Replacement of Snubbers on Supports 491505G and 490010

- PDCR 2-063-92* ESAS Module Upgrade
- PDCR 2-155-92* 4.16 kV Bus Undervoltage/Overcurrent Coordination
- PDCR 2-015-92* Modify the MP2 Service Water Pump Bearings and Lube System

* Indicates that the PDCR was a Short Form PDCR.

During the preparations for plant heatup, the team verified selected plant system readiness for operation. The team confirmed that Operations critical drawings were updated, required preoperational training was completed, station procedures were updated, and other administrative items required prior to declaration of system operability were completed. Generally, the team found that items required prior to release for system operation were completed. No safety issues or issues that impacted licensee progress in plant restart were identified. However, the team identified several discrepancies relating to PDCR completion as described by procedure ACP-QA-3.10.

2.9.A PDCR Completion Deficiencies

ACP-QA-3.10 implements procedure NEO 3.03 that is the corporate level procedure that describes the plant design change control process. These procedures contain detailed instructions for preparation, review, and dispositioning of the design changes and were developed to ensure that the plant safety analysis is not compromised by any subsequent plant changes. The team identified the following deviations from the requirements of procedure ACP-QA-3.10. Specifically, the team was concerned with the use of short form PDCRs where inappropriate, the updating of procedures prior to returning systems to service, PORC review of PDCRs and the closeout of completed PDCRs.

2.9.A.1 Use of PDCR Short Forms

Procedure step 4.1.5 states that "a PDCR Short Form should be used only if very little detailed engineering design work is required to make the plant design change." The NU used a PDCR Short Form to control the upgrade of the ESAS Modules. This project involved over three years of engineering and procurement work with the module vendor including development of the new module prototype, inspection of vendor processes, and review of vendor bench test procedures. All of this engineering effort was performed before initiation of the PDCR. The team questioned under what design control process was this engineering effort controlled and documented. NU responded that this engineering effort was controlled by the project purchase order to the vendor (No. 881661) under ACP-QA-4.02C, "Preparation and Review of Purchase Requisitions (NEO 6.02)." Pending additional review of the appropriateness of using a purchase order to control NU and vendor engineering activities, this issue remains unresolved **(UNR 50-336/92-36-01).**

2.9.A.2 Procedure Updates Associated with Modifications

Procedure step 4.6.2 states that "operations and emergency procedures must typically be updated before the design change is declared operational." The team identified several examples in which Operations department procedures were not updated prior to system release for Operations. Specifically, the emergency operating procedure (EOP) changes required as a result of the MSLB modification (PDCR 2-114-92) were not implemented prior to the system release for operations on January 5. The revised EOPs were PORC approved on December 31, 1992, but were not scheduled to be implemented until January 8, 1993 (later moved up to January 7). The team noted that at the time of PORC approval, plant heat-up and reactor criticality were scheduled for January 1 and January 3, respectively. Similarly, abnormal and operating procedures as well as the control room annunciator response procedure book were not updated following deletion of the shutdown cooling interlock by PDCR 2-014-91. This modification removed the auto closure interlock on high pressure to the shutdown cooling discharge valves and installed two new annunciators in the control room. At the end of this inspection, the procedures affected by this modification had not been updated, although a memorandum from engineering to operations that requested revision of these operating procedures was added to the control room night order book on January 1. A third example of an operating procedure that was not updated involved the 'A' service water pump modifications under PDCR 2-015-92. Operating procedure (OP) 2325A, "Circulating Water System," was not updated to reflect that this pump is now self-lubricating and that following condenser backwashing or "mussel cooking" evolution, the circulating water pump must be run for about 15 minutes prior to starting this service water pump to prevent pump overheating. The fourth example involved modifications to the emergency diesel generator pre-lube actuator on the control room panel which was changed under PDCR 2-071-92. The pre-lube push button was changed to a switch; this affected OP 2346A, "Emergency Diesel Generators." Although this procedure was used to start the emergency diesel generators several times following the modification, a procedure change was not made to reflect this change until January 6. The failure to revise the above noted procedures prior to system release for operations is contrary to the intent of procedure ACP-QA-3.10.

2.9.A.3 PORC Review Responsibilities

Step 4.6 of procedure ACP-QA-3.10 requires that prior to Plant Operations Review Committee (PORC) or Site Operations Review Committee (SORC) review of the PDCR, that "the project engineer and plant engineer agree and indicate, on the PDCR, items which must be completed." Also, procedure step 4.6.2 requires that the engineers "list all necessary procedure revisions on Form B, Section 15 or Section 17." During review of the original PDCR packages, the team noted that for several PDCRs, there was no documentation following the approval for construction signatures (section 12). Specifically, the team noted that PDCRs 2-014-91, 2-007-92, and 2-123-91 were missing information such as the construction, turnover, and preoperational test requirements, and the pre-determined lists of affected plant drawings and procedures (sections 15 and 17). In response to this observation, NU stated that, generally, the sections of the PDCR following the PORC/SORC review signoff (section 12) are not filled out prior to PORC/SORC review and that these committees do not consider this information in the approval of a design change. The Unit Director later acknowledged that this practice is not in accordance with ACP-QA-3.10.

Attachment 1 to procedure ACP-QA-3.10 provides instructions for preparation of a PDCR Short Form. Section 3.3 of this attachment states that "PORC/SORC also ensures that procedures are updated to adequately reflect any plant changes resulting from this PDCR Short Form process." PORC assurance of procedure changes is also described in Attachment 4, Step 10.3 to ACP-QA-3.10. The team noted that this responsibility is not included in section 4.9 of procedure ACP-QA-3.10 that describes the requirements for initial PORC/SORC review of a PDCR. In response to this observation, the Unit Director stated that PORC currently does not meet this PDCR review responsibility.

2.9.A.4 Engineering Responsibilities Prior to Modification Release to Operations Staff

ACP-QA-3.10 section 4.14 details the requirements to be completed prior to engineering release of the PDCR for operation. This section stated that the engineer must verify that the operations critical drawings have been marked up to reflect the changes, and that the necessary procedures are updated to reflect the modification. Following completion of these verifications, the engineer signs section 16 of the PDCR form to indicate that the system is released for operation. As mentioned above (regarding step 4.6.2), the team identified several examples in which the operating procedures were not updated prior to engineering release for system operation. In addition, the team identified that, prior to system release for operation (December 18) and emergency diesel generator operability, the Operations critical drawing (25203-26010) for the 'B' diesel generator had not been updated to reflect the addition of two manual isolation valves to the governor oil booster (2-DG-123B) and main bearing oil booster (2-DG-122B) under PDCR 2-071-92. This drawing was subsequently marked up on January 5. Also, the team noted that many of the PDCR packages reviewed after system release for Operations had not been signed off up to and including section 16 of the PDCR form. The team noted that NU currently relies on the individual engineers to complete the administrative aspects of their design change projects prior to plant restart with no in place management verification process.

2.9.A.5 NRC Conclusions and NU Corrective Actions

Quality Assurance Procedure (QAP) 3.0, "Design Control," implements the requirements of 10 CFR 50, Appendix B, Criterion III to establish measures to ensure that the plant design basis is correctly translated into specifications, drawings, procedures, and instructions. Appendix B, Criterion V, "Instructions, Procedures, and Drawings," specifies that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings; this requirement is implemented by QAP 5.0, "Procedures, Instructions and Drawings." At Millstone, procedure ACP-QA-3.10 is the governing procedure for making plant design changes and translation of these changes into the associated plant documents. The failure to specify station documents affected by a PDCR prior to initial PORC approval and update operating procedures and one drawing prior to system release for operations is a violation of procedure ACP-QA-3.10. Additionally, the failure of PORC to assure during their initial review of a PDCR that the engineering organization has determined and specified all of the plant documents (i.e., procedures and drawings) that are affected by the design change is a violation of procedure ACP-QA-3.10.

Following questions by the team regarding NU assurance that all PDCR actions required prior to plant restart were completed, NU promptly queried all engineers who implemented design changes and later developed a PDCR status matrix. This matrix was completed on January 8, 1993, following plant entry into operational mode 3. There were 139 PDCRs implemented during this refueling outage. NU determined that 38 PDCRs required Operations procedure changes, 26 required drawing changes and 16 required operator training. NU concluded from this review that the majority of the PDCRs did not impact plant restart and that there were no safety significant items missed during the process of engineering release for system operation. This effort confirmed NU's confidence that no items significant to safety were left incomplete in the PDCR release process.

On January 11, 1993, the engineering manager discussed with the team the following lessons-learned from this matrix development exercise: 1) The implementation of the PDCR turnover process needs to be strengthened with clearer guidance to the engineers of management expectations; 2) Some type of PDCR completion tracking system would aid in plant awareness of PDCR impact on plant restart status and provide accountability for completion of individual design changes; 3) ACP-QA-3.10 is weak in areas and contributed to confusion regarding personnel responsibilities and requirements in the control of the design change process; and 4) the engineering manager stated that this information would be shared with his counterparts at the other units. The Unit 2 Director concurred with these items and further stated that he expects that necessary procedure changes will be completed prior to release of future PDCRs at Unit 2.

The team noted that NU has a Performance Enhancement Program (PEP) action plan (AP 2.3.2) for upgrading the design control process. This plan encompasses the entire design process rather than just procedure NEO 3.03. NU presented to the team the plan scope and status. To date, NU has completed process mapping and a procedure impact matrix for the current design control process. Ten project groups have been established and tasked with developing a better design control process and manual to implement this process. NU stated that these inspection results will be factored into the process mapping for the development of the design control manual. The design control manual is scheduled for completion in January 1994 and implementation later that year.

The Unit Director and Station Vice President met with the team on January 29, 1993, to discuss these findings. NU agreed that short term improvements in the design change control process are warranted and committed to implement the following short term corrective actions. The initial PORC reviews of PDCRs will verify the accuracy of the modification and its safety evaluation accurately reflect the PDCR implementation plan, the administrative impact of the change on plant procedures and drawings, and the schedule for implementation of the administrative changes. The accomplishment of all these steps of the PDCR form will be filled out prior to the PORC review. Also, prior to PDCR release for system operation, the Engineering Manager or his designee will review the PDCR package to verify that all required items have been completed and the modification is ready for turnover. These corrective actions will be effective until May 8, 1993 at which time they will be reevaluated. In the interim, NU plans to perform an evaluation of the weaknesses in the current process and modify the short term corrective actions as necessary until the long term corrective actions can be implemented under the PEP.

Following full evaluation of the significance of the inspection findings, NU's proposed short and long term corrective actions and the lack of similar previous violations in this area, the NRC elected to exercise enforcement discretion on the two aforementioned violations as described by Section VII.B of the NRC Enforcement Policy. The team was concerned that these procedural compliance issues were allowed to exist for so long. The inspectors concluded that the proposed corrective actions were comprehensive and that the schedule for implementation was reasonable.

2.9.B Control of Field Changes to PDCRs

When changes are necessary to PDCRs for which the safety evaluations have already been PORC approved, NU typically uses the Design Change Notice (DCN) process to evaluate and implement the change. The use of DCNs to PDCRs and other design documents is governed by procedure ACP-QA-3.14 and is used in lieu of a formal revision to the PDCR provided that certain criteria regarding the significance of the change are met. Design change notices are categorized as either major (functional) or minor (non-functional) changes. Procedure ACP-QA-3.14 lists examples of major changes as the alteration of mechanical or structural integrity; alteration of the control, instrumentation, operation, performance, maintainability, or accessibility for test or inspection; addition or removal of equipment, parts, components; and alterations that change the basis or conclusions of the safety evaluation as specified in the PDCR. This last example, a major change that alters the safety evaluation, is also classified as a significant change and requires a revision to the PDCR and PORC approval prior to the system release for operations. Minor changes are non-intent changes that do not alter the design.

The team reviewed 21 DCNs associated with the following PDCRs to verify that implementation of these changes was done in accordance with procedure ACP-QA-3.14:

• 3 DCNs to PDCR 2-014-91	Shutdown Cooling Auto-Closure Interlock Deletion
• 1 DCN to PDCR 2-114-92	Modifications for Main Steam Line Break Scenario
• 4 DCNs to PDCR 2-007-88	Auxiliary Feedwater System Steam Bypass Line
• 3 DCNs to PDCR 2-056-90*	X-18A, B & C Excess Drain Piping and Hanger Removal
• 1 DCN to PDCR 2-069-92*	X-18A, B & C Excess Drain Piping and Hanger Removal
• 6 DCNs to PDCR 2-178-92*	Replacement of Snubbers on Supports 491505G and 490010
• 3 DCNs to PDCR 2-063-92*	ESAS Module Upgrade

* Indicates that the PDCR was a Short Form PDCR.

The team found that DCNs to these PDCRs typically involved items such as material specifications, minor piping location changes, and missing or deficient construction drawings. All of the 21 DCNs reviewed met the criteria for DCNs and were implemented in accordance with procedure ACP-QA-3.14.

However, in review of DCNs associated with PDCRs 2-063-92 and 2-114-92, the team identified a weakness in the DCN process regarding the performance of safety evaluations for major design changes. Specifically, the team identified two examples in which a new component installation was added to a PDCR without documentation of the basis for the determination that the original safety evaluation was unaffected. For example, NU implemented PDCR 2-063-92, "Engineered Safeguards Actuation System (ESAS) Module Upgrade" during this outage to improve system maintainability since the system was obsolete and many of the parts were no longer available. This change involved manufacturing, installation, and testing of new ESAS modules. As discussed in section 3.3 of this report, during system post-installation testing, NU observed flickering of the new ESAS sequencer lights (LEDs) and experienced inadequate sequencer operation for Facility 1. NU determined that the new ESAS sequencer module was affected by noise spikes caused by an electromagnetic field induced by operation of the actuation relay coils. The ESAS module vendor and NU determined that the installation of diodes across the coil of each actuation module relay would suppress the system noise and thereby permit the new ESAS system to operate as designed. This change was implemented under DCN DM2-P-387-92. The plant and project engineering staffs reviewed this DCN and concluded that it was not a significant change and did not impact the original safety evaluation and therefore could be implemented without revision to the PDCR. The basis for the determination that the safety evaluation was unchanged was not documented. Although not required by procedure ACP-QA-3.14, the addition of these diodes and the impact on the safety evaluation was discussed at length by the PORC; the diodes were installed under PORC-approved vendor procedure KPL 7136, "Field Change Procedure Diode Installation 9N21-5 & 6."

The second example of this weakness noted by the team were related to the plant changes made under PDCR 2-114-92 to ensure plant system actuation to mitigate the consequences of a main steam line break accident. This PDCR involved changes to and additions of various safety injection actuation system (SIAS) start signals and setpoints as well as provided new power supplies for the feedwater system regulating valves (FRV). During the plant heatup, post-modification testing identified that the FRV bypass valves did not close in the time required. NU determined that the existing valve positioner needed to be replaced with a positioner that relieved the control air more rapidly and thereby allow the valves to close faster. The replacement of the valve positioners with a different positioner was made under DCN DM2-S-0014-93 to PDCR 2-114-92. Engineering review of this DCN concluded that this replacement was not a significant change and therefore did not require revision to the PDCR. The basis for this determination that the original safety evaluation was unaffected was not documented.

When changes are made to the plant, 10 CFR 50.59 requires that a safety evaluation shall be made to determine if the change involves an unreviewed safety question (USQ). This safety evaluation must provide a written basis for the determination that the change does not involve a USQ. The responsibility for reviewing these USQ determinations for all changes or modifications to plant systems or equipment that affect nuclear safety resides with the plant operation review committee (PORC) as detailed in Technical Specification 6.5.1.6.

For the above examples, no safety impact on the plant was noted; the modifications were properly installed and tested. However, the team was concerned that safety evaluations were not being performed for such major changes to the plant (as defined in ACP-QA-3.14) as the two examples noted, though PORC may or may not have reviewed the significance of these changes. If a major DCN is determined to be significant, a PDCR revision is required and the effect on the USQ determination is documented in the PDCR and reviewed by PORC. However, for major DCNs determined by engineering to be insignificant, the current DCN process does not provide for deliberate review of the change to determine whether the change involves a USQ. Procedure ACP-QA-3.14 does not require documentation of the basis for determining that the change is not significant nor does PORC review the USQ determination. While the team noted that the responsible engineers for DCNs followed ACP-QA-3.14, the procedure lacked a clear definition or threshold for those changes that constituted modifications that needed a USQ determination. The team concluded the above noted incidents were not consistent with TS 6.5.1.6 and 10 CFR 50.59 as these requirements pertain to the evaluation of field changes to PDCRs.

The team discussed with NU the aforementioned use of DCNs, their interpretations of minor, major, and significance classifications and whether a safety evaluation is needed for such changes to plant systems. NU acknowledged the team's concern that the basis for the USQ determination was not documented or reviewed by PORC. NU stated that the current PEP action plan to review and revise the design change control process will address weaknesses in the DCN process and that these inspection findings will be factored into this evaluation. In the short term, NU committed that PORC will review all DCNs to PDCRs prior to system release for operation to verify that the changes do not involve a USQ. These corrective actions will be effective until May 8, 1993. NU plans to perform an evaluation of the weaknesses in the current process and modify the short term corrective actions as necessary until the long term corrective actions can be implemented under the PEP.

Following evaluation of these inspection findings and their significance, NU's proposed short and long-term corrective actions, the team elected to exercise enforcement discretion for this matter as described by Section VII.B of the NRC Enforcement Policy. The team concluded that NU's proposed corrective actions were adequate and that the schedule for implementation was reasonable.

2.9.C PDCR Summary Findings

The team reviewed 12 percent of the PDCRs implemented during the outage for completion prior to plant restart. Violations of the administrative control procedures as they relate to completion of administrative items prior to system release for operation were identified. Also, the team was concerned that the required safety evaluations were not being performed for major changes to approved plant modifications made under DCNs to PDCRs. No items of safety significance that would affect plant restart were identified. Prior to the end of the inspection, NU proposed short term corrective actions to be implemented across the site. Long term corrective actions will be developed as part of the PEP action plan to revise the design control process. This project is scheduled for completion in 1994. The team noted that there were no previous events at Unit 2 that were caused by inadequate closure of PDCRs prior to system release for operation.

3. RESOLUTION OF OUTSTANDING ENGINEERING/TECHNICAL SUPPORT ISSUES IN SUPPORT OF PLANT RESTART

3.1 Steam Generator Replacement Project Completion/Testing

The replacement of the two steam generators at Unit 2 was extensively reviewed by the NRC during the Summer and Fall of 1992. NRC Inspection 50-336/92-17 verified that all required American Society of Mechanical Engineers Code tests were planned, but at that time, the procedures were not available for review. Therefore, the team reviewed the test procedures to conduct this post-modification testing and observed testing activities that verified the satisfactory installation of replacement steam generators.

The team reviewed the test results and safety evaluation for the reactor coolant system (RCS) leak and hydrostatic tests to verify the structural integrity of the RCS. These tests were performed in accordance with Operations surveillance procedure 2602C, Revision 5 and In-Service Test (IST) 91-05, Revision 0. The structural integrity of the RCS was verified by successful completion of the leak test at an RCS pressure of 2310 psia and a temperature of 533°F. Acceptance criteria for the leakage and hydrostatic tests included visual examinations of accessible insulated and noninsulated RCS pressure retaining components. The examinations required by the procedure included all primary side welds, instrument tubing, floor areas or equipment surfaces located underneath visually inaccessible components and the external portions of insulated surfaces. In addition, the team reviewed the 10 CFR 50.59 safety evaluation for the hydrostatic leak test and verified that the temperature and pressure at which the test was to be performed was acceptable.

The team determined that NU satisfied the acceptance criteria established for the leak and hydrostatic tests. Prerequisites and acceptance criteria described in the tests were clear and consistent and were appropriately reflected in the safety evaluation. The team observed the conduct of the hydrostatic test and performed independent verifications of the test point visual inspections; no deficiencies were identified.

The team also reviewed the procedures and conduct of other significant post-modification testing of the steam generators including the following tests:

- IST 92-12, "Steam Generator Support Clearance Measurement"
- IST 92-16, "Steam Generator Performance Test"
- IST 92-30, "Steam Generator and Containment Temperatures In-Service Test"
- IST 92-73, "Steam Generator Replacement Pipe Support In-Service Test"

The team determined that the testing was planned and conducted in accordance with station requirements. Much of the testing involved gathering baseline performance data that may be used in future performance evaluations. No discrepancies were identified. A moisture carryover test was planned and the procedure was being written at the time of the inspection.

3.2 Completion of Modifications in Support of the Analysis for a Main Steam Line Break (MSLB) Inside Containment

During reanalysis to support the replacement of the steam generators this outage, NU identified that the existing main steam line break (MSLB) analysis was not conservative with respect to containment response. To provide a permanent solution to the identified problem, NU proposed a change to their license and modified aspects of the Unit 2 design that mitigated the effects of a MSLB inside containment with offsite power available. These modifications ensured that primary containment pressure remains below its 54 psi design limit.

The modifications to the plant to correct the identified vulnerabilities were made under plant design change record (PDCR) 2-028-92, "Containment Pressure Signal to Main Steam Isolation Function," and PDCR 2-114-92, "Required Modifications for Main Steam Line Break Scenario." The plant modifications included:

- Starting the Diesel Generators on a safety injection signal;
- Reducing the containment spray setpoint from 27 to 9.48 psi;
- Repowering the feedwater regulating valves (FRV) control circuits from non-vital to vital AC power;
- Providing redundant main steam isolation (MSI) automatic closure signals to the feed pump discharge valves, FRVs, and FRV bypass valves;
- Providing MSI trip signals to the main feed pumps; and,
- Actuating MSI on either low steam generator pressure or high containment pressure.

The team walked down the control panels to verify that the modifications to the annunciator windows and control switches were properly labeled. In addition, they reviewed surveillance and emergency operating procedures to ensure that the changes were incorporated and adequately reflected the plant modification. The team observed and reviewed the post modification test procedures for adequacy and reviewed the Operations critical drawings to ensure they adequately reflected the changes. They also reviewed other administrative PDCR items required for completion prior to releasing the system to Operations.

During the performance of test procedure T92-18, "Automatic closure of Feedwater Block Valves 2-FW-42A & B with an ESAS Main Steam Isolation Signal," the team noted a minor procedural adherence deviation in that the test director requested the operator to reset all eight of the steam generator pressure trip lights while step 7.2.4 of the test procedure specified resetting four. Similarly, the team noted that step 7.2.8 of T92-18 required resetting four versus eight of the steam generator block bistable lights. The team informed the test director of the apparent discrepancies. The procedural steps were subsequently changed to reflect resetting all eight of the trip lights. During the remainder of T92-18 and for the performance of the remaining MSI testing, the team noted that test control and procedure adherence were very good. The team noted that NU was delayed in completing these modifications due to the inability of the feedwater bypass valves to close in the time required. Modifications to the valve positioners were required to ensure that these valves would close sufficiently fast. Concerns with the evaluation of these modifications are discussed in section 2.9 of this report.

The implementation of these modifications had the impact of changing the environmental qualification (EQ) profile inside the containment building following a MSLB inside containment without a loss of normal power. This change had the potential to question the existing environmental qualification of electrical equipment inside containment. In order to ensure that the EQ profile had not been negatively impacted by these modifications and that the existing qualification of electrical equipment remained valid, the team discussed this technical concern with NU engineering personnel in their corporate office.

The team noted that an NRC unresolved item was raised in inspection report 50-336/91-28 regarding the adequacy of the environmental qualification of electrical equipment inside containment following the identification of the MSLB analysis error in October 1991. Review by the NRC in inspection report 50-336/92-23 indicated that the electrical equipment required to be available to mitigate this MSLB event was qualified and would have been operable during such an event. The analysis to support this conclusion was contained in a Justification for Continued Operation (JCO 2-91-1) developed by NU to allow the unit to return to power operations following the identification of this analysis error. Since the post-MSLB environment used in the JCO was more harsh than the environment that is analyzed to exist in the containment following an MSLB with the aforementioned modifications in place, the team concluded that the previous NRC conclusion regarding the adequacy of the environmental qualification of this equipment remained valid. Further, the team reviewed elements of the analysis provided in support of the Technical Specification (TS) amendment requested to allow the installation of these modifications. They confirmed that the performance of the equipment modified was consistent with the assumptions made in the analysis (e.g., that the valves isolating feedwater would terminate feedwater flow in less than 14 seconds) and thus that the EQ profile is no more harsh than estimated.

The team concluded that the plant modifications were implemented properly, procedures and drawings sufficiently reflected the modifications, and that post modification testing was comprehensive. The assumptions made in the current analysis regarding feedwater isolation time in the event of a MSLB inside containment with offsite power available as well as the qualification of electrical equipment inside containment are valid. The minor procedure deficiencies indicated an apparent lack of attention to detail during procedure development and validation. Other issues regarding PDCR changes handled by DCNs are discussed in Section 2.3.

3.3 Integrated Testing of Engineered Safeguard Actuation System

During this refueling outage, NU made several modifications to the engineered safeguards actuation system (ESAS) to upgrade older components that contained obsolete parts and to correct system design deficiencies that were identified following the loss of normal power (LNP) event on July 6, 1992. The LNP event and the subsequently identified design deficiencies were inspected following the event and are discussed in NRC Inspection Report 50-336/92-22.

Modifications were made to the ESAS systems under the following four plant design change records (PDCRs):

- PDCR 2-152-92 ESAS ATI Test Window Modification/SRAS Logic Modification
- PDCR 2-063-92 ESAS Module Upgrade
- PDCR 2-155-92 4.16 kV Bus Undervoltage/Overcurrent Coordination
- PDCR 2-078-92 RPS Pressurizer Alarm Modification

The team observed selected portions of modification installation and post-modification testing. Testing was performed under Operations surveillance procedure SP 2613C, "Engineered Safety Features System Integrated Test," Revision 16; SP 2631G, "Integrated Test of Facility 1 Components," Revision 4; SP 2631H, "Integrated Test of Facility 2 Components," Revision 3; and special test T92-67, "Simulated Loss of Two Vital AC Panels." The following is a brief description of the testing performed, test deficiencies, and deficiency resolution.

The NU conducted the first integrated test SP 2631C on December 15. This was primarily an operations retest, therefore there was no instrumentation of the ESAS system. During the test, engineering personnel observed flickering of the ESAS sequencer lights (LEDs). When compared to the sequencer actuation and the plant computer sequence of events printout, the flickering was determined to be occurring prior to the actual sequencer actuation. NU engineers determined that the flickering was caused by noise in the system that occurred during relay actuation when major load changes occurred by either stripping off or loaded on to the emergency buses by the actuation modules. They determined that the LEDs were much more sensitive to the relay actuation noise than the original incandescent light bulbs that had been removed. The relay actuation noise has existed since original sequencer installation, but was not identified previously because the incandescent light bulbs were not sensitive to this phenomenon. This problem was observed on Facility 1 only; NU attributed the lack of problems in Facility 2 to the differences in physical wiring configuration between the facilities.

A second test deficiency was observed during the December 15 test in which the Facility 1 sequencer did not go through the sequence fully. The sequence started and then before completing the loading sequence, the loads were stripped and the sequence reinitiated. Similarly to the LED flickering, these perturbations were coincident with actuation relay induced noise. The vendor (Eaton Consolidated Controls) recreated this problem in the lab by use of relays similar to those installed at Unit 2. To eliminate this problem, noise suppression diodes were installed under a design change notice (DCN) to PDCR 2-063-92. Further discussion of this DCN is contained in Section 2.3 of this report.

On December 18, NU retested Facility 1 with a mini-LNP test under SP 2631G. All equipment operated as designed, although they observed a slight flickering of the sequencer LEDs. This flickering did not affect the operation of the sequencer as before. Although the LED flickering was not an operability concern, NU has taken an action item to resolve this phenomenon.

On December 19, NU performed the retest for PDCR 2-152-92 under T92-67. This test was designed to demonstrate operability of the sequencer automatic test insertion (ATI) system following modification. During this test, the sequencer operated as expected, but none of the loads stayed tied on to the bus. Following troubleshooting, NU determined that some inverters in the sequencers in both facilities, supplied by the vendor, were installed backwards (these inverters supply the sequencer ATI inhibit function). In essence, the ATI was pulsing the system and stripping off the loads. The ATI inhibit function had not been simulated by the vendor during ESAS module bench testing. NU had been aware of the bench test limitations and therefore tested this function under T92-67. The two spare sequencer modules were sent back to the vendor for rework and subsequently installed in the plant.

On December 26, T92-67 was reperformed. Facility 2 operated as designed, but Facility 1 failed to operate. NU identified a blown fuse in the sequencer module; the fuse was promptly replaced.

On December 27, a full LNP was reperformed under SP 2631C. Facility 2 operated as designed, but the Facility 1 sequencer stopped at sequence step 4. This sequence step automatically starts two air handling fans, one chilled water pump, and one chiller associated with cooling of safety-related equipment rooms. The team observed NU troubleshooting of the sequencer. A burned out chip in the sequencer module was identified and the chip was replaced. This chip controlled only the sequencing action of the module. The retest was conducted by vendor procedure KPL 7136 under automated work order M2 92 19144. The team verified that the retest fully proved that the sequencer would operate as designed; all functions of the sequencer were demonstrated to be operable.

Prior to NU removing their test equipment, the team questioned whether the sequencer retest had fully satisfied the test deficiency identified during the December 27 LNP test. Test personnel consulted with Operations personnel and determined that a retest would have to be performed with a simulated LNP signal to demonstrate that sequence step 4 does start the required equipment. A procedure change was written to KPL 7136 and NU satisfied the test deficiency by demonstrating that during an LNP, the sequencer would power and start all of the equipment that had not operated as designed in the December 27 full LNP test.

NU concluded that the blown Facility 1 sequencer module fuse and inverter chip were probably related. These components are part of different circuits of the sequencer, but they are physically located in very close proximity to each other on the sequencer board. NU engineers postulated that inadvertently the fuse was shorted and 24 volts applied to the chip pin at the lab or during installation at the site. The team verified the close proximity of these components and concurred with their postulated cause.

NU's troubleshooting activities during these series of tests were good. The team concluded that through performance of the multiple overlapping tests noted, NU fully demonstrated that the ESAS system will function as designed with the modifications made during this outage.

3.4 Integrated Leak Rate Test Observations/Results

The team observed portions of the Integrated Leak Rate Test (ILRT) conducted on the Unit 2 containment building. The test was performed according to procedure SP 21208, Rev. 0. The test was performed using a total time leakage methodology that allowed for the use of a reduced duration hold at test pressure. The team observed preparations for the conduct of the test, the functioning of the containment monitoring equipment (i.e. temperature sensors, dew point sensors) used during the test and observed the acquisition of data at test pressure. The performance of the test appeared to be satisfactory.

The team reviewed the procedure following the completion of the test. The team verified that NU conducted the test at the proper test pressure, that the test acceptance criteria were within design requirements and were met during the test and that the basic requirements of 10 CFR 50, Appendix J were met. The team also reviewed selected results from the local leak rate testing program to identify those containment penetrations that exhibited excessive leakage as well as checked the test report from the last ILRT conducted at Unit 2.

Overall, no deficiencies with either the test procedure or the conduct of the test were noted. The results of the test were satisfactory. These results will be finalized in the near future and the results provided to the NRC in the final ILRT test report as required by 10 CFR 50, Appendix J, Section V.B.

3.5 Motor Operated Valve (MOV) Testing

The team ascertained through direct observation and documentation review that the dynamic testing of motor-operated valves (MOVs) is being conducted in accordance with approved procedures, acceptance criteria, Technical Specification requirements and appropriate industry codes and standards. This testing was to verify that these MOVs could function under design-basis accident conditions.

The team reviewed NU's static and dynamic testing of the Auxiliary Feedwater Pump Discharge Header Crosstie Valve, 2-FW-44, on December 12, 1992. The valve passed a static open and close test, but under dynamic flow conditions, the valve failed to close completely. The actuator was, at that time, set to deliver the maximum thrust of 18,147 pounds at a torque switch setting of 3.50. NU issued Nonconformance Report (NCR) 292-1099 to resolve this test failure. NU subsequently reviewed the thrust window calculations and found that the setting was too low. The target thrust was recalculated and a new torque switch setting of 4.25, that was still within the manufacturer's upper torque switch setting range, was recommended to provide a maximum closing thrust of 25,082 pounds. The retest of 2-FW-44 on December 28, 1992, with a torque switch setting of 4.25 verified that the valve opened and closed under static and dynamic conditions. NU's review of the above failure was underway at the time of this inspection. NRC follow-up of this matter will be incorporated under existing unresolved item 50-336/92-27-03.

The team observed the static and dynamic testing of containment spray actuation valve 2-CS-4.1A. During the static test, observations were made at the valve to verify that the stem traveled properly and that the diagnostic equipment was properly installed. The valve operated fully open and closed during static and dynamic testing. The design basis differential pressure of 285 pounds was established initially during testing. However, because of the piping configuration, design basis flow was never achieved. Thus this dynamic testing never verified the ability of this valve to open under design flow. This issue remains unresolved pending a review of NU's actions to test this valve under design flow conditions **(UNR 50-336/92-36-02)**.

3.6 Service Water Flow Adequacy (Preliminary Generic Letter 89-13 Testing Results)/EDG Cooling Concerns (OI 92-04-04; Closed)

During the performance of testing and analysis in accordance with Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," NU preliminarily determined that the service water system was capable of performing its design function up to a service water temperature of 60 degrees F. However, the ability of the system to perform its design basis function up to the service water design temperature of 75 degrees F requires further analysis and cannot yet be proven. In particular, for service water temperatures between 60 and 75 degrees F, the AC and DC vital switchgear area cooling may not meet design requirements (although NU notes that the design heat removal requirements in these areas are excessively conservative). Further, the Reactor Building Closed Cooling Water System (RBCCW) may experience excessive cooling water temperatures with service water temperature between 60 and 75 degrees F, although there also does not appear to be a clear basis for the conservative restrictions on the RBCCW temperatures.

In response to these findings, NU placed a series of restrictions on the operation of the service water system pending the completion of analyses on the system. In particular, NU established that the position of certain valves in the service water system be limited to a specified maximum opening to ensure proper service water system flow in the event of an accident. In addition, analysis to support operation of the system at service water temperatures from 60 to 75 degrees was continued with a goal of completion in February 1993.

The team reviewed the engineering analysis performed on the service water system (SE-92-1377) and discussed the restrictions imposed on the operation of the system with the responsible engineer. In particular, the team discussed the likelihood that NU engineering would be able to confirm the adequacy of service water system operation at service water temperatures between 60 and 75 degrees F. The team also verified the position limits on the noted valves in the service water system as well as confirmed that Operations had administrative controls on the position of these valves. In addition, the team reviewed the procedural restrictions placed in Operations Procedure OP 2326A, Rev. 16, dated January 12, 1993, governing the operation of the service water system. The team confirmed that all the restrictions on the operation of the system noted by NU engineering were in-place.

Overall, the team found NU's corrective actions to date in this matter satisfactory. However, until NU can confirm the adequacy of the design of the system for service water temperatures of between 60 and 75 degrees F, this matter remains unresolved (**UNR 50-336/92-36-03**). The team noted that service water temperatures at the time were about 40 degrees F and dropping, that service water temperatures will not rise above 60 degrees F until at least May and that NU's analysis of the design of the system should be completed in February. Therefore, the team had no safety concerns with the operation of the system until the completion of the analysis in late February 1993.

The team also noted additional restrictions on the operation of the service water system based on concerns with non-seismic service water system line breaks affecting emergency diesel generator operability, specifically limiting the opening maximum opening of the turbine building closed cooling water (TBCCW) system heat exchanger outlet valves and isolating the service water system from the domestic water system. However, these restrictions to some degree overlapped the other aforementioned restrictions placed on the system. The team noted that NU had sufficient administrative controls in place implementing these restrictions, that permanent corrective actions were being pursued, and that the Operations department was knowledgeable of these restrictions and had placed them in their procedures.

On a related issue, the team also reviewed NU's corrective actions in response to concerns with the flow of hot emergency diesel generator (EDG) coolant to the inlet air cooler causing a reduction in EDG power output at high loads and high service water temperatures. The team confirmed that NU had incorporated cautions in the operating procedure for the EDGs (OP-2346A) to ensure that the valve isolating coolant flow to the air cooler is closed under these conditions (as identified during surveillance testing) and that NU has permanent corrective actions planned to correct this design deficiency. Based on NU's corrective actions, the team considers open item 50-336/92-04-04 closed.

3.7 Azimuthal Power Tilt

A Combustion Engineering designed nuclear facility (Waterford 3) recently reported (Event Number 24736) that a discrepancy existed between the azimuthal power tilt assumed in the core safety analysis (10% tilt) and their technical specification limit of 3%. The team reviewed this report for applicability to Millstone 2. Technical Specification 3.2.4 for Millstone 2 specifies that the azimuthal power tilt not exceed 2%. The team found this limit to be consistent with the 2% power tilt assumed in the safety analysis for the current core cycle as well as the previous two cycles.

3.8 Analog-to-Digital Conversion in the Rod Position Indication System/Response Time Testing Results

During this outage, NU elected to replace the Control Element Assembly Position Display System (CEAPDS) with a Combustion Engineering design replacement display system. The system, which converts analog signal inputs regarding the position of the CEAs to a digital output, was of concern to the team due to general NRC concerns with the unknown failure modes of such analog-to-digital systems in the industry. The team reviewed and observed the extensive response time testing performed on the system as well as examined the safety evaluation performed on the modification. The team did note that the safety evaluation was previously revised in light of previous NRC concerns with the analog-to-digital conversion performed on the refueling bridge controls.

The testing was performed under special test procedure T92-72, "CEA Monitoring Response Time In-Service Test," Rev. 0. The test involved the slow withdrawal of the control rods (while shutdown and borated to the TS required shutdown margin exclusive of the control rod reactivity worth) to test the new digital CEA drive system interlocks provided by the CEAPDS. Due to the unique nature of this test, elements of this test were observed by the team in the control room, specifically the monitoring of the reactivity of the core, the results of hourly sampling of the RCS boron concentration and the cautious and conservative movement of the CEAs by licensed operators. Overall, the test was conducted in a safe and conservative manner, although several technical problems had to be remedied to allow the completion of the test. Adequate precautions were taken to ensure that the reactor would remain highly subcritical during the conduct of this test and that activities that could cause a boron dilution were avoided or could be promptly detected by boron sampling. The results of the test indicated that the system performed satisfactorily.

3.9 (Closed) LER 91-003, Potential Loss of DC Switchgear Cooling During a Loss of Instrument Air (UNR 91-15-02)

Licensee Event Report 91-003 identified a design inadequacy that would have caused the loss of DC switchgear room cooling if instrument air had been lost without a concurrent safety injection actuation. NRC inspection report 50-336/91-15 identified an unresolved item (91-15-02) pending NU actions in response to Generic Letter 88-14 and NRC follow-up of NU corrective actions to address root causes of deficiencies. The team reviewed NU's response to the Generic Letter and their preventative maintenance conducted during this outage associated with the instrument air system.

To prevent problems with plant systems using instrument air, NU implemented an extensive preventive maintenance program. Monthly preventive maintenance is conducted on each air compressor, dryer/filter assemblies are inspected semi-annually, and filters are replaced annually. During the steam generator replacement outage, NU conducted a full walkdown of the instrument air system to identify leaks, unexpected corrosion or wear, or other problems. Identified deficiencies were reviewed by engineering personnel and work orders were authorized as necessary to correct the problems. Additionally, NU completed replacement of certain air solenoids to upgrade the design pressure rating for these components. NU's efforts to ensure instrument air reliability appear to be satisfactory; therefore, unresolved item 50-336/91-15-02 is closed.

3.10 Annunciator Power Supply Replacement

Due to previous failures, both at Millstone and in the industry, of the annunciator power supplies currently installed at Unit 2, PDCR 2-134-92 was issued to replace these power supplies with an updated power supply manufactured by Lambda Electronics. The new power supplies provide a one-for-one replacement of the present supplies in performance with a number of improvements such as test points and test switches to provide for on-line evaluation of power supply performance. The power supplies also have alarms in response to degraded power supply performance as opposed to an alarm that activates only when the power supply has failed. The power supplies were replaced and the PDCR was completed several weeks following the return to power operations. The existing power supplies were considered by NU to be adequate for power operation based on past acceptable design and adequate performance during Loss of Normal Power testing conducted prior to plant heat-up.

3.11 Ventilation Flow Concerns to the Swing ECCS Cubicle

NU identified that the ventilation system for the Engineered Safeguards Facility Rooms appeared to have a design deficiency or may have not been analyzed for airflow requirements associated with the start of the 'B' HPSI pump. The 'B' HPSI pump is considered the swing HPSI pump and is located in the 'C' ECCS cubicle. This concern was identified during their ongoing program to improve the performance and reliability of ventilation systems in the plant in light of Millstone and industry experience. Specifically, the 'A' and 'B' room ventilation systems supply the 'C' ECCS cubicle when the 'B' HPSI pump starts. However, the diversion of airflow from the 'A' or 'B' ECCS cubicle that has all three ECCS pumps in that cubicle operating has the potential to allow that cubicle to overheat while the 'C' ECCS cubicle is provided with excessive airflow.

In the interim to correct this deficiency, NU installed a jumper device consisting of a shift supervisor caution tag on the 'B' High Pressure Safety Injection Pump start switch and two lifted relay leads that disable the opening signal that the 'C' ESF room dampers receive when the 'B' HPSI is started. In the future, these dampers will be manually positioned from the control room. The team reviewed this bypass jumper, the caution tags on the 'B' HPSI pump, the Operations procedure changes made in support of this change and the safety evaluation that accompanied the bypass jumper. No deficiencies were noted. NU is currently evaluating a permanent design change to correct this design deficiency.

4. OBSERVATIONS OF RESTART OPERATIONS/TESTING

4.1 Precriticality Testing

The team performed extended observations of control room activities prior to heat-up. The team noted a clear separation of duties between the on-shift control room operators and Work Control Center personnel. This arrangement allowed on-shift control room operators to focus on reactor safety and plant operations without being distracted with processing and coordinating maintenance and retest activities. The team concluded that this separation of duties was a strength.

The team observed the performance of the following surveillances and procedures to support the operational readiness testing of all three charging pumps prior to the plant entering Mode 2:

- SP 21118, Revision 6, "Charging Pump 'A' (P-18A) Operational Readiness Test"
- SP 21119, Revision 6, "Charging Pump 'B' (P-18B) Operational Readiness Test"
- SP 21120, Revision 6, "Charging Pump 'C' (P-18C) Operational Readiness Test"
- SP 21131, Revision 6, "Chemical and Volume Control System Valves Operational Readiness Test"

The team noted that the reactor operators adhered to the procedures, good communication existed between Operations and Maintenance Engineering while the test was performed, and test results met the established acceptance criteria.

During plant heatup, a reactor operator observed the D reactor coolant pump (RCP) trip alarm was actuated, but the D reactor coolant pump current indicated that the pump had not tripped. Operations review indicated that because of the low RCS temperature, one of the phases of the RCP overcurrent relay was tripping intermittently; this condition cleared when the RCS temperature rose. It was noted by the team that this condition caused the audible alarm to continue. (After many attempts to reset/silence this alarm, it was left actuated). This alarm, which lasted for a number of hours, made any other alarms undetectable by audible means. The team concluded that NU's subsequent review of the cause of this alarm was satisfactory.

During the heatup at 396 psi pressurizer pressure, the team observed that the "Back Press CNTL, PIC-201" was still in manual, although OP2201, Rev. 22, Step 4.10, requires "when pressurizer pressure is approximately 350 psi to 380 psi, place back press CNTL, PIC-201 in auto." The operators considered this procedure deviation acceptable since the normal operating procedure 2304A allowed operation in this manner and the controller did not provide the level of fine pressure control desired in this operating pressure range. After discussions with the team, the shift supervisor indicated that a procedure discrepancy and recommendation form would be submitted to correct this procedural deficiency. The team noted this procedure discrepancy and discussed the action taken by the operators with management. A review of Operating Procedure 2304A did verify that operation in manual was approved. Nevertheless, this procedure discrepancy was a longstanding problem that should have been corrected. Furthermore, procedure discrepancies of this type are inconsistent with management's stated goal of improving procedure compliance.

During the heatup, while approaching 350°F reactor coolant temperature, a hold was established at 348°F while it was determined that RCS nickel concentrations were below 100 ppb. The control of Ni in the reactor coolant system was to limit its activation to Cobalt and thus reduce radiation dose as part of their "ALARA" program. The team questioned the SRO to determine how he verified that Ni was below 100 ppb. The SRO and shift supervisor were unaware of this holdpoint requirement and if chemistry had sampled for this element. A telephone call to the Chemistry Supervisor at home ascertained that a sample had been taken the day before and was 72 ppb. Based on these discussions, the team concluded that while NU's efforts to control Ni levels was commendable from an ALARA standpoint and the sampling in question had been performed, there was a lack of communication to the shift on whether this requirement had been accomplished or that it was necessary.

During the heat-up, the team questioned an SRO about entering TS action statement 3.3.3.8. when changing modes with a main steam radiation monitor inoperable. The SRO did not realize that the radiation monitor was inoperable. The TS and conditions of the action statement when this monitor is inoperable were reviewed and it was determined that the action statement was met. The SRO subsequently entered the TS action statement and verified that repair plans for the monitor were in-place.

Overall, Operations performance during the heat-up was quite good. Operators were quite proficient given the extended length of the outage, were aware of changing plant conditions, knowledgeable of plant design modifications made during the outage and were shielded from excessive distraction by the outage control group. Minor procedure compliance concerns and communications problems were noted by the team. While none were safety significant, they indicate the need for continued attention to detail.

4.2 Start-Up Testing

The team observed control room activities during the approach to criticality, which occurred on January 10, 1993, as well as during a number of the low power physics tests. Following the satisfactory completion of those tests, power was raised to 18 percent to warm the main turbine in preparation for an overspeed trip test. The turbine was later taken off-line and the overspeed test was satisfactorily completed. Reactor power was then slowly increased to 30 percent for power range instrument calibrations. During these power changes, the team observed that control room operators were attentive to their duties. Procedures were followed for controlling plant operations and the operators responded promptly to alarms and indications as they occurred. Operations management was observed in the control room throughout the team inspection and interaction between the control operators and the management was good. The team observed shift turnovers and pre-shift briefs were conducted with each crew at the beginning of shift activities. Operators were kept aware of plant conditions and plans for continuing the power escalation.

The team observed the conduct of T90-22, "Automatic Dump Valve Inservice Inspection." During the test, operators monitored and controlled steam generator level and pressure, and RCS temperatures as the ADVs were cycled both locally and remotely to demonstrate proper operation. The test was performed while ensuring that plant parameters were kept within the control bands. The ADV testing was satisfactory and no problems were identified.
The team also verified compliance with Technical Specification 3.6.1.1, "Containment Integrity" by verifying the performance of SP-2605F, "Leak Test of Containment Access Door Gaskets." The test is required every 72 hours when containment integrity is required and multiple containment entries are being made.

5. ASSESSMENT OF OVERALL PLANT RESTART PERFORMANCE/MANAGEMENT OVERSIGHT AND SAFETY ASSESSMENT DURING RESTART

Unit 2 restart was generally conducted in accordance with Technical Specification requirements and testing was conducted in a safe and controlled manner. Management oversight of the restart was evident and Operations performance was good. The team noted adequate configuration control by the outage control group in preparation for the heat-up, although there are several other observations in this area documented in NRC inspection report 92-31 that indicated that configuration control lapses did occur. The team was concerned that NU lacked an integrated schedule to coordinate maintenance, retest, valve line-ups and surveillance testing on each individual safety system; however, good internal communications on the part of Unit 2 personnel prevented such problems during the team's observations. NU previously recognized this weakness and has undertaken efforts to correct this weakness as an element of the Performance Enhancement Program (PEP); the changes planned address this weakness.

During the heat-up evolution, the team noted a clear separation of duties between the outage group and the on-shift operators that they considered a key strength in the handling of outage work control. Further, NU's troubleshooting to correct identified problems during testing was sound and thorough. Deficiencies were followed-up, corrected and satisfactorily retested.

However, the team identified a number of concerns regarding the management and administration of design change processes. The team noted a very informal process for tracking and closing out PDCRs that allowed for the return to service of several systems without the completion of all required procedure updates. In addition, this process made the NU's ability to track PDCR closeout prior to restart impossible without extensive communication within the organization. However, it was this extensive communication that prevented the return to service of safety systems that were not fully operable or had all significant procedure changes implemented. The team was remained concerned with NU's frequent use of DCNs to correct design problems when PDCR revisions (which receive a higher level of review) are more appropriate, although no safety impact was noted for the specific examples found by the team. These concerns were discussed in detail with NU who acknowledged the findings in the PDCR tracking and closeout area and with the integrated scheduling of maintenance and surveillance activities. NU is making plans for short-term improvements in these areas and already had long-term plans for improvements in the design control and integrated scheduling areas as part of the PEP.

6. EXIT MEETING

Following the completion of the OSTI, an exit meeting was conducted on February 2, 1993, with Mr. Steve Scace and others to discuss the inspection findings and observations. During the meeting, the short-term corrective actions which NU committed to perform to address the problems noted in Section 2.9 of this report were confirmed. No proprietary information was covered within the scope of the inspection. No written material regarding the inspection was given to NU.

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION
PIPING STRESSES DUE TO COLD SPRING DISPLACEMENTS
NORTHEAST UTILITIES
MILLSTONE UNIT 2

INTRODUCTION

The NRC staff previously reviewed the Northeast Utilities (NU) 10 CFR 50.59 evaluation for the replacement of the steam generators (SG) at Millstone 2 Station. The staff's safety evaluation concluded that the steam generator replacement effort did not involve an Unreviewed Safety Question (Reference 1). For this replacement project, the SG lower assemblies were removed and replaced by new units from B&W Canada. The only SG components retained are the upper portions of the pressure vessel - the steam drums down to the 16'9" diameter portion of the transition cones. Sections of the main steam, feedwater and blowdown system piping, along with sections of instrument tubing, were removed from the SG nozzles back to the biological shield walls, and then replaced after installation of the new steam generators. The reactor coolant system piping was cut at the SG nozzles and later welded to the new steam generators with the same piping configuration.

After the cutting of the reactor coolant system lines, unanticipated pipe movement was experienced on the cold leg piping. The cold legs moved in upward and outward directions, and also moved in toward the SG nozzles. These unanticipated movements were in the order of half of an inch and varied between individual nozzles and directions.

The NRC staff from Region I and the Office of Nuclear Reactor Regulation (NRR) performed several inspections between August 30 and November 6, 1992 at Millstone 2. The purpose of the inspections was to evaluate the extent to which the licensee has established that stresses in the reactor coolant system (RCS) piping after welding will be acceptable for continued service. These inspections focused on activities related to cutting of the pipe, the reported pipe movement, related stress analysis, and engineering evaluations. At the conclusion of the inspections (Reference 2), the issue of cold spring displacement was identified as an open item that needed to be further resolved by the licensee.

In response to the request of NRC Region I Office, the staff of EMEB conducted a follow-up plant site audit, on December 22, 1992, to review the adequacy of the licensee's RCS piping final stress analysis and the nozzle design at steam generators, reactor vessel, and reactor coolant pumps, as a result of the observed pipe movements.

DISCUSSION

The above mentioned cold spring displacements occurred while the cold leg pipe connections on steam generators were being severed. The cold leg piping on each loop was moving in unanticipated directions and magnitudes upward and in toward the steam generator. This motion caused the cold leg piping to jam against the steam generator nozzle and bind up the cutting tool.

A corrective action plan was established by the licensee, with Fluor Daniel and ABB/CE retained as its technical consultants. To resolve the immediate interference between the pipe and the nozzle which was precluding the steam generator removal, it was decided to jack the pipe away from the steam generator and install temporary pipe restraints to hold the pipe in a repositioned configuratioin. To identify all precautions necessary to protect the RCS piping system and NSSS components from being inadvertently overstressed or otherwise damaged during repositioning efforts, the licensee also utilized engineering expertise from NUSCO, in additon to the above two outside consultants. One of the efforts recommended was to apply pipe-end jack forces incrementally and analyze at each point to ensure that an overstressed condition would not occur.

As a result of the pipe movements experienecd during cutting of the first steam generator (SG #2) pipe connections, on July 12, 1992, and after analyzing the applied forces versus pipe repositioning movements, restraints were designed and installed on the second steam generator's (SG #1) cold leg pipe connections prior to the RCS cutting which started on August 14, 1992. Similar displacements were again observed. Cold leg pipes again moved in toward the steam generator nozzles and had to be jacked away to permit removal of the steam generator.

In an attempt to identify the root cause of the unanticipated pipe movements, and to predict the RCS response to the effects of jacking and other repositioning efforts, the licensee also engaged the technical firm AEA O'Donnell on July 17,1992. Additionally, an independent review team, headed by the supervisor of the corporate stress analysis group, was also established to coordinate all the above consultants' efforts. To augment corporate resources the licensee further engaged Donald Landers, a Teledyne consultant, who had performed pipe stress analyses for NU in the past. The team identified the following three primary contributors to the observed displacements:

1. Piping displacements due to the design deadweight reactions at the cut location.

2. Piping displacements due to weld shrinkage during construction.

3. Piping preload resulting from the out-of-sequence post weld heat treatment (PWHT) of the RCS cold leg piping.

In addition, the team determined, prior to the completion of the final stress analysis, that the RCS piping could not be overstressed by repositioning the pipe, based on the following factors:

1. A preliminary analysis indicated relatively low pipe stresses and nozzle moments associated with the pipe cold spring.

2. The relatively large magnitude of forces required to reposition the pipe far exceeded the capacity limitations of the installed jacks and their structural anchorages.

The limitation on jack capacity, in turn, also defines the fact that the pipe could not be restored to the precut position by jack forces alone. It was determined, therefore, to jack the pipe as close as possible to the precut position and machine-fit the remaining mismatch to achieve fit-up. The corresponding pipe-end displacements resulted from such jacking-machining efforts were then measured and are referred to as final fit-up displacements, which were, in turn, used for the purpose of the final pipe stress analysis.

EVALUATION

The staff has reviewed the details of the licensee's corrective action plan (Reference 3). The staff feels that the licensee has taken the initiative of engaging extensive outside consultants for performing the reanalyses as well as independent review. Based on this, the staff determined that the licensee's actions to resolve the cold spring issue are acceptable. The staff also reviewed the final stress reports (Reference 4 through 8) provided by the licensee for RCS piping, steam generator nozzles, reactor vessel nozzles, and reactor coolant pump nozzles.

The licensee used the above final fit-up displacements as boundary displacements for the reanalysis of RCS piping and components. The system stress levels as well as the end forces and moments at the cold legs were first determined for a computer model of RCS piping, with the steam generator removed, and with the pipes repositioned by the magnitudes of the final fit-up displacements. The system stress levels were then determined for the same RCS piping model, with the new steam generator now installed, and with the previously calculated end forces and moments applied at the cold legs. Finally, a complete ASME Code Section III piping analysis were performed for the latter RCS piping and components, considering all the design basis loading conditions - for pressure, deadweight, thermal, and seismic - as well as the loading due to the final fit-up displacements. The stresses in piping and at nozzles were all found to be within the ASME Code allowables, under each of the design loading requirements, and, therefore, are acceptable. Fatigue analyses were also performed by the licensee and the results were also found to meet the ASME Code requirements.

In the process of the above final analyses, situations were identified where design considerations were made in the calculations that caused some overstressed conditions. Evaluations by the licensee revealed that these incidents were mostly due to inadvertent use of overly conservative design parameters. They were subsequently corrected. The situations involved the followings:

1. Use of fit-up displacements which were not corrected for the deadweight displacement.

2. Use of fit-up displacements which represented the enveloped displacements of all nozzles, instead of displacements for the individual nozzles, in the stress analysis.

3. Fit-up loads were treated as a primary load, instead of a secondary load, in the RCS piping analysis.

4. In the analysis for the reactor coolant pump nozzles, the design-basis earthquake (DBE), instead of the operating-basis earthquake (OBE), was used for the ASME Code Section III Level A design condition with OBE allowable.

The staff also performed spot checking of the consistency between the computer outputs and the design calculations, and vice versa, and found them to be acceptable.

CONCLUSION:

Basis on the above evaluation, the staff concludes that the RCS piping and components remain intact after replacement of the steam generators, despite the fact that cold spring displacements occurred during cutting of the cold legs from the replaced steam generator nozzles. The licensee's corrective action plan was found to be comprehensive, and the methodologies used for the pipe stress analysis and nozzle design were found to be in conformance with ASME Code Section III requirements and are acceptable.

REFERENCES:

1. Memo, J.A. Norberg to J. F. Stolz, dated July 27,1992.

2. NRC Region I Inspection Report No. 50-336/92-26, dated December 4, 1992.

3. Millstone 2 SGRP Independent Technical Review Team Report, dated November 30, 1992.

4. "Millstone II - Loads Due to Fit-Up of Cold Legs," Calculation No. N-ME-C-019, by ABB Combustion Engineering Nuclear Services, dated December 8, 1992.

5. "The Effect of Replacement Steam Generator Fit-Up Displacement Loads on the RCS Piping of Millstone Unit II," Calculation No. N-MECH-CALC-019, by ABB Combustion Engineering Nuclear Services, dated December 10, 1992.

6. Letter, Babcock & Wilcox to Northeast Utilities Service Company, on "Primary Piping Cold Spring Loads," dated November 23, 1992.

7. "Millstone Unit 2 Reactor vessel Inlet Nozzle Analysis to Include Replacement Steam Generator Fit-Up Loads," Calculation No. N-MECH-CALC-018, by ABB Combustion Engineering Nuclear Services, dated December 10, 1992.

8. "The Effect of Replacement Steam Generator Fit-Up Displacement Loads on the Reactor Coolant Pumps of Millstone Unit II," Calculation No. N-MECH-CALC-020, by ABB Combustion Engineering Nuclear Services, dated December 16, 1992.

MEMORANDUM FOR: A. Randolph Blough, Chief
Reactor Projects Branch 4

FROM: Lawrence T. Doerflein, Chief
Reactor Projects Section 4A

SUBJECT: **INSPECTION COVERAGE DURING MILLSTONE UNIT 2 RESTART**

Enclosed is a plan to provide augmented coverage starting December 28, 1992, for the Millstone Unit 2 restart. We plan to provide about two days of augmented coverage verifying heat-up and start-up preparations, then three to four days of around-the-clock coverage, commencing about 12 hours prior to entry into Mode 4. Follow-on augmented coverage should last approximately 1 week, the amount of time for the plant to reach 100% power.

Paul Swetland will manage the team effort and Rich Barkley will be the team leader. Rich will coordinate the inspection activities and be responsible for compiling the inspection report. Shift coverage will be provided by A. Asars, R. Arrighi, P. Sena, R. Barkley and M. Buckley, as needed (see Enclosure 2). The current schedule calls for shift coverage to begin on December 30, 1992; alternate schedules have been proposed if the plant start-up is delayed.

Richard S. Barkley

for Lawrence T. Doerflein, Chief
Reactor Projects Section 4A

Enclosures: 1) Augmented Inspection Coverage for the Millstone Unit 2 Restart
2) Personnel Availability for Unit 2 Restart Team

cc w/enclosure:
Unit 2 Restart Coverage Team Participants
J. Wiggins
P. Swetland
W. Pasciak
D. Jaffe
J. Durr
R. Barkley

AUGMENTED INSPECTION COVERAGE FOR THE MILLSTONE UNIT 2 RESTART

OVERVIEW

Based upon the decline in performance of Millstone Station in the previous SALP cycles and the length of the Unit 2 steam generator replacement/refueling outage, augmented inspection coverage is planned to monitor NU management oversight and control of start-up activities and to verify proper operator performance.

NRC INSPECTION COVERAGE

This inspection effort has been planned to monitor plant start-up activities both before and after NU and the NRC have ascertained that the unit is ready for start-up. The inspectors will verify some start-up preparations during approximately the final two days before heatup. The Team Manager and Team Leader will select items from the NRC Millstone Unit 2 Restart Checklist and NRC Manual Chapter 93802, Operational Safety Team Inspection (OSTI), during this period. Twenty-four hour shift inspection coverage is planned for the first two or three days of the Unit 2 start-up and will begin about 12 hours prior to entry into Mode 4. The need to continue around-the-clock coverage will be reassessed on the basis of licensee performance and progress during the start-up. The proposed shift coverage will provide the basis for an assessment of the effectiveness of management oversight and operator performance. The team manager will assess the need for continued shift coverage on an ongoing basis. Shift coverage may be deferred during stagnant periods of start-up activity. The shift coverage will be terminated upon achievement of the inspection goals and after consultation with Region 1 management. Thereafter, only significant evolutions would be covered. The period of augmented inspection (approximately 1 week) should cover ascension to 100% power.

INSPECTION ACTIVITIES

The following key activities will be reviewed during shift coverage:

- Heatup and start-up prerequisites (including independent verification)
- Shift crew briefings and turnovers
- Management and plant operations review committee meetings
- Test data reduction and evaluation

- Mode change preparations and safety system alignments (Technical specification verification)
- Reactor Start-up and low power physics testing
- Main turbine start-up and synchronization to the grid
- Dynamic tests of motor-operated valves (Generic Letter 89-10)
- Steam generator and containment temperature in-service test
- Steam generator performance test
- RCS hydrostatic test
- RPS/ESFAS systems testing
- Safety-related equipment maintenance

PRE-INSPECTION PREPARATION

Each inspector should review the following documents prior to arrival on site.

- MC 93802, Operational Safety Team Inspection
- The OPS, ENG, and SA-QV sections of the latest Millstone SALP (50-336/90-99)
- Inspection report 50-336/90-22; Containment integrity violations
- Inspection report 50-336/92-04; Entry into Mode 4 with no operable HPSI train

PROCEDURE

Each inspector will monitor NU during their assigned shift. Shift coverage will, as best possible, parallel NU's schedule with a short period before shift for turnover and after the shift for de-briefing. Findings or concerns will be recorded in a shift inspector log in order to centralize all observations. The inspectors should monitor the following specific types of activities during their shift:

- Operator attentiveness to plant activities and conditions
- Formality, safety perspective, and performance of routine functions
- Non-licensed operator performance
- Procedure adherence
- Satisfactory completion of procedure objectives and acceptance criteria
- Technical Specification compliance
- Restoration and testing of safety-related equipment
- Response to non-routine occurrences
- Involvement of management
- Conduct of special tests, including pre-evolution briefings
- Shift team work
- Shift supervisor oversight of shift activities
- Role of QA/QC during job performance
- Problem solving

Manual Chapters 71711, Plant S/U from Refueling, 71715, Sustained Control Room and Plant Observations, and 93802, OSTI, will be used as guidance for this inspection effort.

DOCUMENTATION

All inspectors will provide write-ups to the team leader for incorporation in the team inspection report, preferably prior to departure from the site but in no case less than a week later.