U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report: 50-336/88-06

Docket No: 50-336 License No: DPR-21

Licensee: Northeast Nuclear Energy Company

Facility: Millstone Nuclear Power Station, Waterford, Connecticut

Inspection at: Millstone Unit 2

Dates: February 8, 1988 through March 21, 1988

Inspectors: Peter J. Habighorst, Resident Inspector
William J. Raymond, Senior Resident Inspector
Eben L. Conner, Project Engineer, DRP Section 1B

Approved: Ebe C. McCabe, Jr 4/13/88
E. C. McCabe, Chief, Reactor Projects Section 3B Date

Inspection Summary: February 8 - March 21, 1988 (Report 50-336/88-06)

Areas Inspected: This inspection included routine NRC resident (135 hours), and region-based (17 hours) inspection of previously identified items, plant operations, surveillance, radiation protection, physical security, fire protection, Temporary Instruction (TI) 2515/86, mechanical and hydraulic snubbers, and review of periodic and special reports.

Results: No violations or unsafe operational conditions were identified. Additional follow-up is warranted on control of overtime, I.E. Bulletin 85-03, and fire protection for auxiliary feedwater isolation valves.

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DETAILS

1. Persons Contacted

Mr. S. Scace, Station Superintendent
Mr. H. Haynes, Station Services Superintendent
Mr. J. Keenan, Unit 2 Superintendent
Mr. J. Riley, Unit 2 Maintenance Supervisor
Mr. J. Smith, Unit 2 Operations Supervisor
Mr. D. Kross, Unit 2 Instrument and Controls

The inspector also contacted other members of the Operations, Radiation Protection, Chemistry, Instrument and Control, Maintenance, Reactor Engineering, and Security Departments.

2. Summary of Activities

Millstone 2 began the inspection period in cold shutdown while completing the Cycle 9 refueling and maintenance outage. On February 13, the unit commenced heat-up to normal operating temperature and pressure. The heat-up was aborted on February 14, due to a failed "D" Reactor Coolant Pump seal (Section 10.0). On February 16, heat-up recommenced, and the reactor was made critical on February 18 at 5:28 p.m. On February 25, the unit was at 100% power, and remained at that power level through the end of the inspection period.

The following activities were addressed by the inspector during the recent outage: in-leakage testing of the control room, observation of plant heat-up and approach to criticality, verification of high pressure safety injection (HPSI) system alignment during start-up, completion of the Engineered Safety Feature (ESF) integrated test, observation of Control Element Assembly (CEA) drop times, mechanical and hydraulic snubber review, and Plant Operations Review Committee (PORC) meetings. The inspector observed planning and implementation of containment inspection prior to start-up physics testing, and utilization of a second dedicated senior reactor operator (SRO) in the control room to track prerequisites and requirements for heat-up. Good overall direction and overview by the licensee were noted.

3. Licensee Action on Previously Identified Items

3.1 (Open) Violation 87-16-01: Fire Protection for Auxiliary Feedwater Isolation Valves 2FW43A & B (92701)

This item concerned the lack of a 20 foot separation between redundant valves 2FW43A & B as required by 10 CFR 50 Appendix R Section 111.2.b. NRC and licensee review during inspection in July 1987 identified no safety concern. The licensee instituted compensatory measures by starting and maintaining an hourly fire patrol of the area. In the October 23, 1987 response to the Notice of Violation, the licensee stated he would seek an exemption from the regulations, and that the fire patrol would be maintained until the staff approved the exemption request.

The licensee submitted a request for exemption from the Appendix R requirements relative to 2FW43A & B by letter dated February 29, 1988 and notified the inspector that he intended to discontinue the fire patrol of the area. The reason for the action was that there was no benefit of having the patrol since, as documented in the bases for the exemption request, there were no safety concerns with the existing plant configurations. The licensee requested NRC concurrence in the intended action.

The inspector toured the valve area to review the area for fire hazards, and reviewed the Fire Hazards Analysis provided in the February 29 exemption request. The inspector noted that there were no transient combustibles in the area. The inspector noted further that the valves are designed to fail open upon loss of power and/or air supply to the valve positioners. The inspector concurred with the licensee's technical determination that no safety hazard existed since any fire in the area affecting both valves would not prevent the valves from opening, or prevent the auxiliary feedwater system from performing its intended function.

After consultation with NRC management, the inspector informed the licensee on March 4, 1988 that the NRC staff did not concur with discontinuing the fire patrol. The inspector informed the licensee that the patrol should be maintained until the NRC approves the exemption request or approves discontinuing the fire patrol. The licensee acknowledged the inspector's comments and stated that the fire patrol would be maintained. The inspector verified periodically during the inspection period that the fire patrol covered the area.

The inspector had no further comments at this time. Resolution of the licensee's exemption request will be followed up in subsequent routine inspections.

3.2 (Open) IE Bulletin 35-03, Motor Operated Valve (MOV) Common Mode Failure During Plant Transients Due to Improper Switch Settings (92702)

The licensee's June 11, 1986 response addressed six specified actions related to the subject bulletin. (This response was reviewed for timeliness and content in Inspection Report 50-245/86-17 for Millstone 1.)

IE Bulletin 85-03 specifies that motor-operated valves (MOVs) in the high pressure coolant injection, core spray, and emergency feedwater systems should be tested for operational readiness in accordance with 10 CFR 50.55a(g), and that licensees should develop and implement a program to ensure that components are selected, set, and maintained properly. The licensee's reply concluded for Millstone 2 that the review specified by IEB 85-03 applied to the Auxiliary Feedwater (AFW), the High Pressure Safety Injection (HPSI), and the Chemical and Volume Control (CVC) systems. The bulletin provisions are addressed as follows:

a. Design Bases for Motor-Operated Valves (MOVs)

The licensee was to review and document the design basis for each MOV including the maximum valve differential pressure expected during both opening and closing for both normal and abnormal events. The licensee identified 4 AFW system MOVs, 16 HPSI system MOVs, and 3 CVC system MOVs to be included in the program. In addition, the licensee included 2 power-operated relief block valve MOVs (2RC-403 and 2RC-405) in the program. The specified design differential pressures for the 19 of the 25 included valves were equal to or greater than the normal and abnormal event maximum differential pressures.

In the June 11, 1986 response, the licensee justified six (6) MOVs with specified design differential pressures less than event maximum differential pressures. For the Terry Turbine steam supply isolation MOVs (2-MS-201 and 202), the licensee found the specified differential pressure of 900 psi (normal operating steam pressure) acceptable based on both redundant steam supply MOVs being normally open and the worst case maximum event pressure being limited to 1065 psi. For the HPSI discharge header crosstie valves (2-SI-653 and 655), the licensee found the specified differential pressure of 1200 psi acceptable based on no safety injection actuation signal (SIAS) for these valves, the requirement that one valve be closed for separation, and maximum discharge pressure being 1250 psi. For the HPSI injection header isolation valves (2-SI-654 and 656), the licensee found the specified design differential pressure of 1200 psi acceptable based on the MOVs being normally locked open and not being required to operate for safety injection. The inspector had no further questions on these valves.

b. Translate the Specified Design Differential Pressure to the Correct MOV Switch Settings

The licensee's response outlines a plan to determine the proper switch settings using a combination of analytical and empirical data. The inspector found that this engineering had been performed but this data was not reviewed during this inspection. The inspector's review will be performed after the final report is submitted.

c. Testing of MOVs to Ensure Valve Switch Settings

The licensee committed to stroke test a sufficient sample of MOVs against a maximum expected differential-pressure and use these results to verify the theoretical torque switch setpoints. MOVs where differential-pressure testing was not possible were to be stroke-tested using the Motor-Operated Valve Analysis and Test System (MOVATS), to the extent practical, to verify that the settings defined have been properly implemented. To this end, NNECO purchased MOVATS equipment and initiated MOV testing at Millstone 2. The inspector reviewed Special Procedure 87-2-5, Procedure for Testing Limitorque MOVs using MOVATS, and observed the physical testing of selected MOVs. The licensee had two testing crews working to complete the testing of 13 MOVs, including flow testing of 8 HPSI MOVs, during the just completed refueling outage. The remaining 12 MOVs are scheduled to be static-tested during plant operation. The licensee stated that MOV findings/resettings will be provided in the final report.

d. Review/Revise Procedures to Ensure Correct MOV Switch Settings

The licensee committed to review and revise procedures to ensure that correct switch settings are determined and maintained. The licensee is working to have the necessary procedure changes in the near future. This aspect remains open.

e. Report the Results of MOV Design Basis Review and Provide the Schedule for Corrective Actions

The licensee's June 11, 1986 letter provides the results of MOV design basis review and commits to complete the other actions for Millstone 2 a couple of months after the end of the current refueling outage. The licensee has established a coordinated and comprehensive MOV testing program that addresses the concerns of IEB 85-03. They now plan a composite report for all 4 units (Millstone 1, 2, and 3 and Haddam Neck) to be submitted to the NRC prior to July 1, 1988. This schedule is acceptable to the NRC. The NRC will review the final report when it is received.

3.3 (Closed) Unresolved Item 87-25-05: Control Room Radiation (93702)

The licensee continued testing of the leak tightness of the control room envelope during this inspection period. On February 11, the licensee successfully completed inservice test T88-05 and verified that control room inleakage was less than the allowable 100 scfm. To do so, the licensee used the emergency technical specification (TS) change for TS 4.7.6.1.e.3 by placing the control room air conditioning system in the isolation/recirculation mode (accident condition). The inspector verified the licensee met the provisions of the emergency technical specification change and complied with the limiting conditions of operations (LCO). No inadequacies were noted. This item is closed.

3.4 (Closed) Violation 87-25-02: Vital DC Chillers Inoperable (93702)

The licensee responded to this item by letter dated February 10, 1988. Licensee actions to restore the vital DC chillers to operable status were reviewed and found acceptable in Inspection 87-25. The licensee reported that the vital DC chillers would be replaced by March 1988 and that emergency operating procedures would be changed to list operator contingency actions to establish alternate cooling methods if the chillers were not available. The inspector noted that the chiller heat exchangers were replaced during the 1988 refueling outage. The licensee initiated actions on 1/18/88 to change the applicable emergency operating procedures. The procedure change commitment was assigned controlled routine number CR 0587-55 with a scheduled completion date of 11/28/88. The inspector identified no inadequacies with the scheduled completion date, based on the continued operability of the chilled water heat exchangers, the changes to OP 23150 and 2330C discussed below, and the operators' general knowledge of the compensatory actions needed to provide alternate cooling to the rooms.

Based on the above, the licensee's actions on this item were satisfactory and this item is closed.

3.5 (Closed) Unresolved Item 87-25-01: Additional Information on the Chilled Water System

The licensee responded to this issue by letter dated 12/4/87 to describe the history of the problems on the vital chilled water heat exchangers and the bases for his actions and schedule to restore the units to an operable condition. The licensee stated that administrative procedures presently in effect for conducting 10 CFR 50.59 evaluations are more thorough and comprehensive than in the past and would better document bases for actions involving inoperable equipment. Additionally, the licensee revised system operating procedures for the vital electrical switchgear cooling (OP 23151, Change 1, 11/3/87) and for the chilled water system (OP 2330C, Change 4, 11/3/87) to provide additional guidance to the operators in the event normal cooling is lost. The inspector reviewed the instructions and identified no inadequacies. This item is closed.

4.0 Observations of Physical Security (81064)

Selected aspects of site security were verified for proper implementation during inspection tours. The aspects of site security included access controls, personnel and vehicle searches, personnel monitoring, placement of physical barriers, compensatory measures, and guard force response to alarms and degraded conditions.

4.1 Vital Area Alarm De-Activation

On March 11, at 8:16 a.m., the licensee reported a security event under 10 CFR 73.71(c). A unit 2 vital area access door was closed and locked, but the associated alarm was deactivated. Upon discovery, the licensee posted the door and searched the area. No discrepancies were noted.

The licensee conducted an investigation to determine why the alarm was deactivated. On March 10, the computer services department was deactivating data points still active in the computer system but not required to be functional. The licensee's work order to accomplish this task was MP-88-01783. The inspector interviewed the licensee to determine the cause for deactivating a vital area access point. The licensee concluded personnel error caused an improper alarm deactivation. In further interviews with the licensee, it was concluded that the vital area access point alarm was deactivated for approximately 23 hours.

According to the licensee, this alarm discrepancy should have been determined by an eight-hour surveillance Security Equipment Surveillance Procedure (SEP) 5073. This surveillance directs the console operator to compare the inactive points list to the security compensatory measures currently in place. During this particular event, SEP-5073 was not performed. During his followup of the event, the licensee determined that SEP-5073 was not completed for about two weeks prior to the event. The licensee stated that completion of this surveillance was not tracked during routine shift activities by the console operator. The licensee's corrective actions are to provide a checklist for all console operators to complete and document on an 8-hour shift basis. The inspector has no further questions in this area. The inspector reviewed the last three surveillance checks completed per SEP-5085 prior to the event on the vital access point in question. This test is completed periodically to verify vital access point alarm functions are operable. The completed test results showed no discrepancies.

The inspector concluded this was a licensee-identified violation. The inspector reviewed the past year Security Event Reports (SERs) to determine licensee's corrective actions for a previous violation and determined if past corrective actions could have precluded this particular event. The inspector also reviewed the reporting requirements under 10 CFR 73.71(c). No discrepancies were noted. The inspector concluded the event i) was identified by the licensee; ii) is of severity level V or or IV; iii) was reported as required; iv) was acceptably corrected, including measures to prevent recurrence; and v) was not a violation that could reasonably be expected to have been corrected by prior corrective actions. Based on the above, no violation will be issued (LII 88-06-02).

5.0 Plant Tours and Operational Status Review (71707)

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

Control Room	Auxiliary Building
Vital Switchgear Room	Enclosure Building
Turbine Building	Fence Line (Protected Area)
Intake Structure	

Control room instruments were observed for correlation between channels, proper functioning, and conformance with Technical Specifications. Alarm - conditions in effects and alarms received in the control room were reviewed and discussed with operators. Posting and control of radiation, contamination, and control of high radiation areas were inspected. Usage and compliance with Radiation Work Permits (RWPs) and uses of required personnel monitoring devices were checked. During plant tours, logs and records were reviewed to ensure compliance with station procedures to determine if entries were correctly made, and to verify correct communication and equipment status. Records included various operating logs, turnover sheets, and tagout logs. Backshift inspections of the control room were performed on February 10 at 1:00 a.m., on February 16 at 9:00 p.m., on March 10 at 5:00 p.m., and on March 20 at 7:00 p.m. Routine power operations and refueling outage activities were observed. Operators were alert and attentive to plant conditions. No abnormal conditions were observed.

5.1 Safety System Operability (71710)

Emergency systems were reviewed to verify they were operable in the standby mode. The systems reviewed were the high pressure safety injection (HPSI) system and the auxiliary feedwater (AFW) system. The inspector used line-up procedures OPS form 2604E-2 for the HPSI system, and OPS form 2610C-2 for the auxiliary feedwater system, to determine positions for major flow path valves. This review verified the valve line-up procedures agreed with the respective piping and instrument drawings 26015 and 26002/26005. No inadequacies were noted. The safety system review also considered operable normal and emergency power supplies, indicators and controls functioning properly, visual indication for component leakage, lubrication, locations of ignition sources or flammable materials in the vicinity, and the overall condition of the system. No inadequacies were noted.

The inspector reviewed the most recent technical specification surveillances on the HPSI and AFW systems to verify the system operability requirements were met, test results were acceptable, and test frequencies were met. Items reviewed were:

Technical Specification	Surveillance
4.7.1.2.1a, 2a, 3, 4	OP-2610A-1 "A" AFW Operability
4.7.1.2.1a, 2a, 3, 4	OP-2610A-2 "B" AFW Operability
4.5.2.a.1 and 4.5.3.1	OP-2604A-1 Facility I HPSI Operability
4.5.2.a.1 and 4.5.3.1	OP-2604B-1 Facility II HPSI Operability

No inadequacies were identified.

5.2 No Fire Watch During Maintenance Housekeeping (93702)

On 3/14 at 10:30 a.m., in the turbine building at the east 56 foot area, the inspector observed grinding operations on a temporary storage cage. The grinding was generating sparks. There was no fire watch. The inspector asked why. The licensee secured the work, posted a fire watch, and resumed work on the temporary storage cage.

The inspector reviewed the licensee's fire hazards analysis. The heat potential for this location is 37,535 BTU/sq. ft., with the combustible material being cables and main turbine lube oil (storage and transient). Inspector review concluded that hot work not properly controlled could have created a significant fire hazard. However, the inspector noted no transient combustible materials in the area and no potential to adversely impact safety-related equipment. Therefore, the inspector concluded that the safety significance was minimal.

The licensee informed the inspector that work on this temporary storage cage was considered housekeeping and was therefore not governed by a work order. (ACP-QA-2.02C, the Work Order procedure, identifies under what conditions a fire watch shall be implemented.) The inspector asked the licensee to review his administrative controls as necessary to assure activities involving ignition sources are appropriately controlled per ACP 2.05B, Control of Combustible Materials, Flammable Liquids, Compressed Gases, and Ignition Sources, if work orders are not applicable. The licensee has informed first-line supervision of this occurrence, and of the need to determine whether fire watches are needed on specific jobs not utilizing a work order. This item is unresolved pending completion of licensee actions and subsequent review by the NRC (UNR 88-06-01).

5.3 Reactor Coolant System (RCS) Unidentified Leakage (93702)

On 3/8 at 8:30 a.m., with the unit at full power, the licensee reported to the inspector an increase in unidentified leakage in containment to 0.37 gpm (an increase from the 0.135 gpm calculated when the unit began full power operation on February 25 after the Cycle 9 refueling outage). The Technical Specification limit for unidentified leakage (TS 3.4.6.2) is 1 gpm. The containment sump boron concentration was 182 PPM. RCS boron concentration was 871 PPM. On 3/9 at 12:15 p.m., the licensee entered containment to search for the source. No leakage was located.

On 3/10, the licensee entered containment, again, for two reasons. The first was to repair SI-661, a solenoid-actuated pneumatic globe valve from the #3 Safety Injection Tank (SIT) to the primary drain tank (PDT). SI-661 had failed leak rate testing during the outage, and the licensee noted level decreases in #3 SIT and an increased frequency of filling the #3 SIT to maintain the level within Technical Specification 3.5.1.B limits. The inspector verified, daily, the level and pressure requirements in all four SIT tanks. No inadequacies were noted. As a result of leakage past SI-661, the licensee prepared 2-ENG-150, Rev. 0, an appendix to the RCS unidentified leak-rate calculation, to account for leakage from the #3 SIT to the PDT. This leakage is not accounted for in the RCS leakage calculation procedure (SP203), but the PDT level changes are included in the calculation performed by the process computer. The inspector independently verified (utilizing SP-203) that the above condition leads to an erroneous result for unidentified leakage. The licensee's second reason for entering containment on 3/10 was to recheck any possible unidentified leakage paths. No leak points were found. Valve SI-661 was successfully repaired at 6:10 p.m. on 3/10. Subsequently, the licensee terminated use of 2-ENG-150.

On 3/11, the licensee's water inventory balance calculated 0.38 gpm unidentified leakage. The inspector utilized data points from the process computer and independently calculated unidentified leakage using SP-203 for guidance. No discrepancies were noted.

The licensee also monitored containment radiation, containment sump pumping frequency, steam generator activity, and total RCS activity trends to detect unidentified leakage. No sources of leakage were identified. As of 3/18, the calculated unidentified leakage was 0.459 gpm. The inspector will continue to monitor licensee activities in this area.

5.4 Engineered Safety Feature Integrated Test Update (62703)

In NRC Inspection Report 50-336/88-02, the inspector had not considered SP-2613C, Engineering Safety Feature (ESF) Integrated Test, successfully completed. The initial start and subsequent restart of the facility II Emergency Diesel Generator (EDG) actuation time for the "C" charging pump for Sequence 2 was in excess of the allowable 8.4 seconds. The "C" charging pump started at 8.7 and 8.8 seconds, respectively. The inspector reviewed the plant computer sequence of events and a video tape of control room panel CO-1 to verify the starting times of the "C" charging pump.

The actuation relay was tested prior to the Integrated Test and was recorded on Instrument and Control (I&C) form 2403H-9. The relay was also tested subsequent to the Integrated Test on Work Order M2-88-02019. The inspector found that relay testing to be satisfactory. No inadequacies were noted.

On 2/9, the "C" charging pump was tested by the licensee using monthly surveillance procedure SP2601H. The charging pump start signals generated via the Engineering Safety Actuation System (ESAS) test switch uses the same actuation module and relay as the Integrated Test. The test results were 0.144 and 0.131 seconds for the two starts. The licensee has committed to monitor the response time for the first four months of Cycle 9 power operation to verify proper operation of the "C" charging pump. The inspector concluded no safety concern existed for the "C" charging pump start times, since an integral time limit of 28.4 seconds (EDG start, and "C" charging pump sequenced on the bus) is assumed for the design base accident conditions and was not exceeded. The inspector had no further questions.

6.0 Temporary Instruction (TI) 2515/86 - Inspection of Licensee's Actions Taken to Implement Generic Letter 81-21, Natural Circulation Cooldown (25586)

Background

While St. Lucie Unit 1 was cooling down under natural circulation on June 11, 1980, flashing of coolant produced a void in the reactor vessel upper head, forcing water into the pressurizer. The reactor was taken to cold shutdown. Multi-plant action item (MPA) F-66 was developed by the NRC to assure that all pressurized water reactors (PWRs) implement procedures and training programs to deal with such events. NRC Generic Letter 81-21 asked licensees to assess their facility procedures and training program, including:

-- Demonstrating (i.e., analysis/tests) that controlled natural circulation from operating conditions to cold shut down conditions, conducted in accordance with plant procedures, should not result in reactor vessel voiding.

-- Verifying that supplies of safety-grade auxiliary feedwater are sufficient to support plant cooldown methods.

-- Describing plant training programs and emergency procedures that prevent or mitigate reactor vessel voiding.

TI 2515/86 provides guidance on satisfactory completion of licensee actions in response to MPA-B-66. Its provisions are addressed in the following.

a. Identify Plant-Specific Requirements from the Licensee's Response to MPA-B-66 (Generic Letter 81-21)

Results:

On October 20, 1983 an NRC safety evaluation was completed on natural circulation cooldown. This evaluation was based on the licensee's response to generic letter 81-21 dated November 19, 1981. The safety evaluation concluded that there is reasonable assurance that steam formation at the upper head of the reactor vessel will not occur during natural circulation. The conclusion was based on a Combustion Engineering study (CE-NPSD-154, Natural Circulation Cooldown Task 430 Final Report) as it applies to Millstone Unit 2, and the existence of sufficient auxiliary feedwater to provide for plant cooldown. However, the licensee submittal (11/19/81) lacked information on the adequacy of training on natural circulation cooldown as it pertains to void formation and consequence, signs of voiding, discussions of procedures to prevent or mitigate voiding, discussions of the St. Lucie Event, and simulator modeling of upper head voiding.

The inspector reviewed training lesson plan M2-OP-RO-FUND-2121J (Reactor Coolant System Heat Removal). The lesson plan explains plant response from single phase natural circulation to two phase natural circulation, two phase natural circulation to reflux boiling, and the criteria used to determine the existence and adequacy of natural circulation. The inspector concluded that M2-OP-RO-FUND-2121J training lesson adequately explains void formation and plant parameters utilized to determine void formation to control room operators. No inadequacies were found.

In lesson plan RO2-20(B), Natural Circulation Cooldown, Step C.5., void control in the RCS is discussed. The operators are taught fundamental methods of mitigating or diminishing the effects of voiding in the Reactor Coolant System (RCS). In lesson plan M2-OP-RO-TA-2026 (Mitigating Core Damage) under Section VII, Major Industry Events, the St. Lucie Unit 1 event was described in detail. The instructor is provided guidance in this lesson plan to question control room operators on why parameters change and on the consequent operator actions. No inadequacies were noted in the application of training lesson plans RO2-20B and M2-OP-RO-TA-2026.

The inspector reviewed Simulator Instructor's Guide RO2-20(S), Natural Circulation Cooldown. Simulator exercise RO2-20(S) provides a scenario to operators for head bubble formation during a natural circulation cooldown. The inspector had no further questions in regards to this matter.

b. Verify That the Training Program Includes Classroom and Simulator Coverage of Natural Circulation Cooldown Procedures by Review of Records, Discussions with Individuals, or Observation of Similar Activities for Three Licensed Operators

Results:

The inspector interviewed training department personnel to determine the program for natural circulation cooldown. The program consists of the following;

i) Classroom Phase - Lesson plan M2-OP-RO-FUND-2121J (RCS Heat Removal) - for fundamental training on heat transfer and thermodynamics for all licensed operators.

ii) Simulator Briefing Room - Lesson plan RO2-20(B), Natural Circulation Cooldown. The lesson plan links fundamental concepts in the classroom and applies the concepts to Abnormal Operating Procedure (AOP) 2553, Natural Circulation cooldown.

iii) Simulator Phase - Lesson plan RO2-20(S). This training provides hands-on simulator training on natural circulation cooldown and the presence of RCS voids.

iv) Training Performance Guide (TPG) 2553 - This lesson plan applies to requalification of licensed operators. It provides a simulator exercise on natural circulation cooldown utilizing AOP 2553 and associated enabling objectives. The inspector reviewed training records on the most recent operator initial qualification and requalification to verify natural circulation training explained above was documented as being completed. No inadequacies were noted.

The inspector interviewed selected licensed operators in the control room concerning the indications of establishment of natural circulation and void formation in the RCS. No inadequacies were noted.

c. Verify That the Licensee Has Emergency Procedures Regarding Natural Circulation - Specifically, Ensure that Procedures for Reactor Vessel Upper Head Bubble Prevention or Mitigation are in Accordance with the Response to Generic Letter 81-21

Results:

Licensee Abnormal Operating Procedure (AOP) - 2553, "Plant Cooldown Using Natural Circulation" is utilized to cooldown the reactor from hot standby to shutdown cooling initiation using natural circulation. The entry conditions for this procedure are: reactor tripped; reactor coolant pumps not in operation; and natural circulation established in at least one loop. No inadequacies were noted.

The inspector reviewed the most recent initial operator qualification "daily student task evaluation" records for RO2-20(S) "Natural Circulation Cooldown." The student task evaluation was reviewed for content, detail and student documentation of successful completion of the simulator exercise. No discrepancies were noted.

An AOP-2553, Step 3.2 precaution provides two specific indications of reactor vessel head voiding for the operator. The indications are:

-- Pressurizer level increase greater than expected while using auxiliary spray.

-- Pressurizer level decrease while operating charging pumps or high pressure safety injection (HPSI) pumps.

Procedure step 4.11 of AOP 2553 directs the operators to observe available indications for void formation during depressurization. Voids may be allowed to remain if the reactor coolant system is greater or equal to 30 degrees F subcooled and at least one steam generator is available for heat removal.

If the above conditions cannot be satisfied, then operator actions under 4.11.c of AOP-2553 are relied upon to reduce or eliminate the void.

The inspector had no further questions in regard to this area.

7.0 Surveillance (61726)

On February 16, the inspector observed surveillance SP-21010, "Control Element Assembly (CEA) Drop Times". This procedure determines the full length CEA drop times (full out to 90% insertion). The maximum drop time permitted by Technical Specification 3.1.3.4 is the assumed CEA drop time used in the accident analysis. The acceptable drop time is less than or equal to 2.75 seconds. The inspector verified that prerequisites and initial conditions for portions of SP-21010 were satisfied. Procedural adherence, granting of administrative approvals, test equipment in proper calibration, and conformance to technical specifications were noted.

During the performance of SP-21010, CEA 5-4 drop time was 2.722 seconds. This value was within the technical specification limit, but in excess of the average rod drop times 2.3-2.4 seconds. A retest was required on rod 5-4 per step 7.2.26 of SP-21010. The licensee concluded that this drop time was attributed to rod bounce as indicated by the lower electric limit reed switch indication. The licensee's retest drop time was 2.371 seconds as recorded by the process computer. The inspector has no further questions in regard to this matter.

The inspector reviewed test data for accuracy and completeness. No unacceptable conditions were identified.

8.0 Mechanical and Hydraulic Snubber Inspection (61729)

In accordance with TS 3/4.7.8, hydraulic and mechanical snubbers were visually inspected and functionally tested during the 1988 refueling outage. All 134 mechanical and 147 hydraulic safety-related snubbers were inspected by a subcontractor. Of these, 122 mechanical and 110 hydraulic snubbers passed without comment. Of the 12 mechanical and 37 hydraulic snubbers requiring further review, 2 mechanical and 8 hydraulic snubbers were determined to be acceptable-as-is by the assigned site engineer. The remaining 10 mechanical and 29 hydraulic snubbers required NUSCO engineering review and disposition. None of the visual snubber problems were considered failures by the licensee.

The inspector reviewed the various surveillance procedures and the visual inspection data including the engineering evaluations. In response to inspector questions, the assigned site engineer provided the following information.

- Reinspection data showing 3/16-inch holes had been drilled 1/2-inch from the toe of the weld to the end attachment per disposition of Snubbers 416014A and B.

- The individual reinspecting a snubber after correcting a deficiency is aware of the original problem.

- No work was done on the steam generator hydraulic snubbers this outage. Inspection of these snubbers is due in 1992.

- The basis for accepting Snubbers 413021, 413023B, and 119R28A as "Acceptable-As-Is" for actual travel less than design was a known error in EP 21157. This error was corrected.

- The "Acceptable-As-Is" dispositions for Snubbers 40101B, 501022A, and 513023B were revised to provide written justification for travel interferences.

- Snubber service life is verified, per TS requirements, since all snubbers were overhauled in 1985 and are, therefore, acceptable until 1990. All replacement snubbers are rebuilt prior to installation.

For the bench testing requirement, the inspector reviewed the Snubber Test Selection List, the testing result packages, and the disposition of testing problems. The 18 mechanical and 17 hydraulic snubbers (10% sample) selected for testing included different sizes of snubbers, and 4 mechanical and 2 hydraulic snubbers that had previously failed. This is in accordance with TS 4.7.8.1.c. The licensee had devised a program to replace all snubbers to be tested with spare snubbers from the warehouse. These replacement snubbers were reworked and tested prior to installation. The advantages of this approach were: (1) reduced time of safety system inoperability; (2) improved control of snubber testing; (3) reduced radiation exposure due to single access of snubber replacement crews into radiation areas; and (4) improved outage efficiency.

The inspector had no further questions.

9.0 Allegation RI-88-A-003, Excess Hours Worked at Millstone 2 (92720)

This allegation involves electricians working more than 16 hours straight, without prior authorization, in July 1987, during a Unit 2 outage. The inspector interviewed the alleger, the alleger's foreman, another involved electrician, and the Millstone 2 Superintendent. The controlling administrative procedure, ACP 1.19, Overtime Controls for Personnel Working at the Operating Station (NEO 1.09), which implements TS 6.2.2.g, provides guidelines on the length of the work-day (not over 16 hours straight or over 16 hours in any 24 hour period), rest time between days (no less than 8 hours between work periods and no more than 24 hours of work per any 48 hour period), and total hours worked per work-week (no more than 72 hours).

The work being performed was the inspection and replacement of jumper wires in safety-related Motor-Operated Valves identified in an NRC inspection as not meeting Environmental Qualification requirements. The four people interviewed believed the MOV inspections and jumper wire replacements were completed correctly. Post-removal inspection showed the jumper wires replaced were all Vulkene Supreme (the environmentally qualified type). The problem had been improper labeling, not incorrect wire.

TS 6.2.2.g. requires implementation of administrative procedures to control working hours of the staff who perform safety-related functions. This issue was the subject of a previous violation in routine Inspection Report 50-336/87-29-01. No response by the licensee was required at that time.

The inspector reviewed the Maintenance Department, I&C Department, and Engineering Department overtime records for the recently completed Unit 2 outage. From the posted total overtime listing in the Maintenance Department, eight names were solicited and compared with all authorizations to exceed overtime sheets and weekly time records for the outage. Twelve individual cases where approval was not obtained prior to exceeding the ACP 1.19 guidelines were identified.

The inspector interviewed first line supervisors in the maintenance department to determine the amount of interface occurring between the workers, the conditions utilized for granting overtime, and the capability of workers to work excess hours especially on safety-related work. No inadequacies were found.

The inspector will continue to pursue overtime controls from the previous outage, and review the licensee response to allegation RI-88-A-003, during the next routine inspection report. This item is open pending that further review (UNR 88-06-02).

10.0 Failure of "D" Reactor Coolant Pump (RCP) Seal (93702)

At 8:20 p.m. on 2/13, during the plant initial heat-up from the Cycle 9 refueling outage, with reactor coolant system (RCS) temperature at 455 degrees F and RCS pressure at 1500 PSI, the "D" reactor coolant pump (RCP) seal high bleedoff flow temperature alarm occurred at 175 degrees F. The licensee secured the "D" RCP at 10:17 p.m. and commenced cooldown for repairs.

On 2/15, the licensee replaced the failed seal per procedure MP-2703E6B, RCP Seal Removal and Installation. The inspector reviewed pre-installation test and overhaul procedures M2-87-13179 and M2-87-13179 for the failed seal. No inadequacies were noted. The inspector also reviewed M2-88-2342, Pre-installation Test, for the replacement seal. This procedure determines control bleed-off flow, breakdown pressure indications, and general overhaul of the seal in a test fixture assembly.

On 3/4, a licensee critique concluded that the cause of failure of the "D" RCP seal was improper installation during the outage. Specifically, the adjusting cap was adjusted incorrectly and the locating pins from the upper pressure breakdown device were removed prematurely. These actions resulted in pre-stress to the shaft seal, causing shaft to seal misalignment and high bleed flow temperature.

Licensee procedure MP-2703E6D addresses removal and installation of a RCP seal with the motor removed. According to the licensee, shaft seal replacement normally occurs with the RCP motor aligned with the associated pump; however, during the refueling outage, the "D" RCP motor was removed and replaced. During installation of the RCP seal, an inadequate turnover by maintenance personnel and miscommunications regarding the final steps of installation of the seal occurred. MP-2703E6B, RCP Seal Removal and Installation (with the RCP motor installed), was used. The inspector asked how the wrong procedure was used for final completion of the seal installation. The licensee responded that procedure MP-2703E6B is normally found in the RCP seal replacement tool box. The licensee specifically provided a new seal replacement tool box with the correct procedure, MP-2703E6D, for the outage. However, in the job-site turnover process, the incorrect tool box and procedure were used. The licensee's critique identified the following actions: face-to-face job site turnover; no procedures in the tool boxes; specific seal alignment training on the seal mock-up; having the same work crew work on the procedure; and quality control hold points in MP-2703E6D and MP-2703E6B to verify adjusting cap and locating pin positions. The inspector had no further questions.

11.0 <u>On-Site Plant Operations Review Committee (PORC) (40700)</u>

The inspector attended Unit 2 PORC meetings on February 9, 12, 16, 19 and March 10. Technical Specification 6.5.1.2 requirements for committee composition were met. PORC topics and review included the following:

-- Plant Design Change Record (PDCR) M2-88-014, "Terry Turbine Drain Line Hanger Modification." This change installs a simple hanger to organize and support various lines emptying into the Terry Turbine room sump.

-- MP 2708A, "Electrical Valve Operator Repairs" Revision 10, Change 1. This procedural change permits adjustment of the torque spring assembly when additional assembly guidance is available.

-- I&C Form 2436D-1, "Safety Related Instrument Start-up Valve Lineup Data Sheet." This change reflects revised instrument valve configurations due to modifications during Cycle 9 refueling outage.

-- OP 2387G, "Inadequate Core Cooling System." This change was made to direct operators to open the door connecting the new and old computer rooms and station a fire watch during periods of extended Loss of Normal Power (LNP) operations. This change was made to incorporate changes made in PDCR 2-4-88, Old Computer Room HVAC Mods.

-- SP 2674, "Pressurizer Spray Line Bypass Valve Adjustment." This procedure incorporates inservice test guidance into an Operations procedure. The PORC concluded this does not constitute an unreviewed safety question per 10 CFR 50.59.

-- PORC commitment 88-3 was initiated to ensure SP 21010 is revised to provide sufficient boron concentration to maintain shutdown margin when withdrawing more than 1 control element assembly (when using the plant process computer for CEA drop time tests).

No deficiencies in PORC performance were observed.

12.0 Review of Periodic (90713) and Special Reports (92700)

Upon receipt, periodic and special reports submitted pursuant to Technical Specifications were reviewed. The review verified that the reported information was valid and include required NRC data. The inspector also reviewed whether any reported information should be classified as an abnormal occurrence. The following reports were reviewed:

-- Monthly Operating Report (88-01) for January 1988

-- Monthly Operating Report (88-02) for February 1988.

-- Special Report submitted in accordance with Technical Specification 4.4.5.1.5.c. This special report detailed the results of the in-service steam generator tube inspections. As a result of the inspection both steam generators were in Technical Specification 4.4.5.1.2.c, Category C-3 which required the licensee to submit a special report prior to resumption of plant operations, and provide a description of investigations conducted to determine the cause of tube degradation and corrective actions to prevent recurrence.

No deficiencies were noted during these reviews.

13. Management Meetings (30703)

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