U.S. NUCLEAR REGULATORY COMMISSION
REGION I

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

Facility: Millstone Nuclear Power Station, Units 1, 2, and 3

Inspection at: Waterford, CT

Dates: April 6, 1994 - May 17, 1994 and July 28, 1994 - August 4, 1994

Inspectors: P. D. Swetland, Senior Resident Inspector
K. S. Kolaczyk, Resident Inspector, Unit 1
R. J. DeLaEspriella, Resident Inspector, Unit 2
R. J. Arrighi, Resident Inspector, Unit 3
D. A. Dempsey, Resident Inspector
V. L. Rooney, Senior Project Manager

Approved by: Lawrence T. Doerflein 8/4/94
Lawrence T. Doerflein, Chief Date
Reactor Projects Section No. 4A

Scope: NRC resident inspection of core activities in the areas of plant operations, radiological controls, maintenance, surveillance, security, outage activities, licensee self-assessment, and periodic reports.

The inspectors reviewed plant operations during periods of backshifts (evening shifts) and deep backshifts (weekends, holidays, and midnight shifts). Coverage was provided for 161 hours during evening backshifts and 65 hours during deep backshifts.

Results: See Executive Summary

EXECUTIVE SUMMARY
Millstone Nuclear Power Station
Combined Inspection 245/94-18; 336/94-17; 423/94-16

EXECUTIVE SUMMARY

Plant Operations

Unit 1 was shutdown throughout this reporting period for the cycle 14 refueling outage. Two engineered safety features actuations occurred due to maintenance personnel error and procedure inadequacies. Operators responded well to the events and implemented appropriate compensatory measures. During an instrumentation logic test on April 10, 1994, 12,000 gallons of reactor coolant were sprayed into the drywell inadvertently. The event resulted from an incorrect procedure which had not been effectively reviewed and approved. Although the operators followed the procedure as written, a more careful shift review of the prescribed system alignment could have prevented the event. An inadequate procedure review and approval violation was not cited because of the extensive licensee response and corrective action to the event. Startup from the outage was delayed by resolution of planned and emergent engineering issues, including recovery from the reactor vessel draindown, and turnover of plant systems. A violation was cited concerning failure to perform independent verification of safety-related valve positions following testing. Subsequent to the plant start-up from the refueling outage, operators failed to identify an anomalous reactor physics condition which developed in the core following a power reduction on July 27, 1994. A reactor engineer identified the condition which degraded the reactor protection system the following day. A violation was cited concerning the failure to make required adjustments to account for the observed core anomaly.

Unit 2 began the report period at full power. On April 22, a plant shutdown was commenced for replacement of a failed reactor coolant pump seal. During the shutdown an immovable control element assembly (CEA) was identified. The CEA was inserted by removing power from its gripper coils, and the reactor was manually tripped shortly thereafter. The plant was placed in the cold shutdown condition (Mode 5) on April 24, where it remained for the balance of the reporting period. During an integrated engineered safety features system surveillance test an unplanned system actuation occurred. The NRC intervened when the licensee decided not to terminate the test in accordance with the procedure termination criteria. An unresolved item was opened to follow the licensee's corrective action.

Unit 3 operated at full power during the reporting period, with the exception of a brief downpower to 50% to perform condenser backwashing. On April 29, a main condenser outlet waterbox was overpressurized and ruptured when the outlet valve was closed inadvertently. The event was ameliorated by prompt operator diagnosis and corrective action.

Maintenance

Two maintenance-related inadvertent engineered safety features actuations involving containment isolation and emergency core cooling systems, and an inadvertent reactor vessel draindown occurred at Unit 1. The licensee's initial review of the first actuation was not fully effective, in part, due to failure to utilize the guidance contained in the post-trip review administrative procedure. The second actuation was caused by inattention to detail and lack of independent verification of important procedure steps by test personnel. In both cases, corrective actions were considered to be adequate and enforcement discretion was exercised. The licensee's initial response to the draindown event including operator response, management control of the resumption of outage activities and drywell cleanup and equipment testing was conducted in an outstanding manner. A good causal analysis was performed; however, corrective action recommendations lacked the clarity needed to assure that the root causes would be effectively addressed. Subsequently, engineered safety feature system integrated tests and a hydrostatic leak test of the primary plant were completed satisfactorily.

Engineering

At Unit 1, an NRC-identified violation of licensee administrative controls for plant design change implementation was cited due to ineffective corrective action for a previous violation. An unresolved item was identified concerning utilization of incorrect input assumptions in an operability analysis of the turbine building closed cooling water system heat exchangers.

Two long-standing issues involving seismic qualification of emergency core cooling systems at Unit 1 were reviewed by the inspector. The licensee's position that the plant could be operated indefinitely under an operability determination was unacceptable. The licensee revised their operability assessments, and committed to resolve the issues by July 1994.

A potential common mode failure mechanism concerning Unit 2 engineered safeguards actuation system undervoltage modules was identified by the licensee. The licensee determined that the modules were degraded but operable. This item is unresolved pending review of the licensee's final evaluations and corrective actions. Unit 2 staff also determined that the mitigation circuitry for an Anticipated Transient Without Scram which was installed to meet the requirements of 10 CFR 50.62 had not been tested each refueling outage. An unresolved item was opened to track this oversight.

The Unit 3 Independent Safety Engineering Group provides high quality and insightful evaluations and observations of unit activities, and meets technical specification requirements. However, more management attention to improve the timeliness of recommendation closeout is warranted.

Safety Assessment/Quality Verification

Two violations of NRC requirements were cited on the basis of inadequate and ineffective action to prevent recurrence. At Unit 2, the licensee did not address the root cause of failure to incorporate cooling water system design temperature limits in plant operating and alarm response procedures. At Unit 3, administrative controls established to control temporary plant modifications (e.g. scaffolds), work documentation, and retests were not implemented effectively in spite of corrective actions taken for previous violations.

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The inspection procedures (IP) from NRC Manual Chapter 2515, Light Water Reactor Inspection Program, that were used as guidance are listed parenthetically for each report section.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

Unit 1 remained in the refueling outage for the entire report period. During this time, personnel error and inadequate procedures resulted in the initiation of two Engineered Safety Features actuations and an inadvertent draindown of the reactor vessel during surveillance testing. Major milestones that were met during the report period included the satisfactory completion of the primary plant hydrostatic and integrated engineered safety features tests. As a result of the inadvertent reactor vessel draindown, the licensee stopped the performance of complex testing pending review of the surveillance procedures by a review team.

During this time period, rework, and slow resolution of planned and emergent engineering issues lengthened the plant outage. At the close of the report period the licensee was making preparations to take the reactor critical. Major activities that were delaying the startup included closeout of discrepant conditions in the drywell and turnover of plant systems.

Unit 2 was operating at full power at the beginning of the inspection period. On April 20, 1994, at 4:23 p.m., operators noted that the volume control tank (VCT) level was decreasing, indicating possible leakage from the reactor coolant system (RCS). The leakage was quantified at approximately 8 gallons per minute (gpm). Operators entered 4-hour technical specification action statement (TSAS) 3.4.6.2b for unidentified RCS leakage greater than 1 gpm. The leak was isolated by 7:30 p.m., so no plant status change was required.

On April 22, 1994, at 9:05 p.m., the licensee commenced a plant shutdown in preparation for an outage to replace the 'D' reactor coolant pump seal. At 1:15 a.m. on April 23, the licensee identified that one control element assembly (CEA) was immovable. At 2:48 a.m. on April 23, the licensee removed power to the gripper coils of the CEA #65, allowing it to fall into the core. Two minutes later the rest of the rods were manually tripped from approximately 1E-5 percent power, and the licensee notified the NRC, state and local officials of the manual scram. The licensee conducted a normal plant cooldown and the plant was placed in the cold shutdown condition (Mode 5) on April 24, where it remained for the balance of the inspection period.

These Unit 2 events were reviewed during an NRC special inspection which evaluated the licensee's actions. The results are detailed in Millstone Combined Inspection Report 50-245/94-20; 50-336/94-18; and 50-423/94-17.

Unit 3 entered the report period operating at 100 percent power. On April 29, the 'E' main condenser outlet waterbox was overpressurized and ruptured when its circulating water outlet valve inadvertently closed. Prompt operator actions to recognize the failure and isolate the waterbox prevented any further adverse consequences. The unit remained at full power. On May 10, power was reduced to 50 percent to perform condenser backwashing while the 'E' condenser waterbox was out of service for repairs. The unit was returned to full power operation on May 11. At the end of the inspection period, reactor power was at 100 percent.

2.0 PLANT OPERATIONS (IP 71707, 93702)

2.1 Operational Safety Verification (All Units)

The inspectors performed selective inspections of control room activities, operability of engineered safety features systems, plant equipment conditions, and problem identification systems. These reviews included attendance at periodic plant meetings and plant tours.

The inspectors made frequent tours of the control room to verify sufficient staffing, operator procedural adherence, operator cognizance of equipment and control room alarm status, conformance with technical specifications, and maintenance of control room logs. The inspectors observed control room operators response to alarms and off-normal conditions.

The inspectors verified safety system operability through independent reviews of: system configuration, outstanding trouble reports and incident reports, and surveillance test results. During system walkdowns, the inspectors made note of equipment condition, tagging, and the existence of installed jumpers, bypasses, and lifted leads.

The inspectors determined these operational activities were adequately implemented. Specific observations are discussed in Section 2.2 to 2.6 below.

2.2 Independent Position Verification of Safety-Related System Valves - Unit 1

On May 3, 1994, the inspector performed safety system walkdowns at Unit 1 during the performance of special procedure SP-681, "Operational Leak Test of the Reactor Vessel." The inspector noted that a temporary test gauge and pressure transducer were installed across the 'A' low pressure coolant injection (LPCI) system heat exchanger at emergency service water (ESW) system vent and drain valves 1-LPC-30A and 1-LPC-14A. As the gauge appeared to be pressurized, the inspector questioned the operators regarding the position of the valves. The valves subsequently were found to be shut. The inspector also questioned the position of emergency diesel generator (EDG) cooling water isolation valve 1-DGCW-7. In 1992, the normal position of valve 1-DGCW-7 specified by the EDG operating procedure valve lineup sheet was changed from open to shut. The change was made to address an EDG electrical loading concern, and was in effect on May 3, 1994. The licensee found the valve to be open.

Administrative control procedure ACP-QA-2.12, "System Valve Alignment Control," step 6.1.1, requires independent verification to be performed of repositioned valves in all safety-related systems following maintenance or surveillance activities. The ESW and EDG systems are listed in station form SF-227-1, "Safety-Related Systems Requiring Independent System Alignment Verification," which is referenced in procedure ACP-QA-2.12. The ACP was established pursuant to Technical Specification 6.8.1.a and NRC Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," step 1.c, which collectively require that procedures for the control of equipment be established and implemented.

The inspector found that the temporary test equipment had been installed across the 'A' LPCI heat exchanger per automated work order M1-94-06072 to support the performance of special procedure SP-94-1-54, "Service Water and Emergency Service Water Thermal Hydraulic Test." No safety tag clearance or other means of independent verification were used to control valve positions for the work. On April 30, 1994, the special test was performed and valves 1-LPC-30A and 1-LPC-14A were positioned by operators at the direction of the system engineer to place the test equipment into and out of service. Aside from a prerequisite step in the special procedure which required the valves to be open at the beginning of the test, the procedure contained no specific steps for manipulation or position verification of the valves. The inspector found that independent position verification of the valves last had been performed on April 22, 1994, prior to conducting the test, and concluded that no independent verification had been performed on the valves during the special procedure and prior to system operability being required on May 3, 1994. This is the first example of a **violation** of the independent verification requirements specified above.

During the current refueling outage, a plant modification was implemented which installed check valves in the EDG jacket water cooling supply and return lines. On April 8, 1994, special procedure SP-94-1-66, "Emergency Diesel Generator Retest," was performed. Although not specifically directed by the procedure, valve 1-DGCW-7 was opened to perform an infrared temperature check to verify that the check valves were closed during EDG operation per procedure step 6.39. At the conclusion of the test, the valve was left open. This was contrary to the normal valve position specified by EDG valve position lineup verification form 338-1. The inspector found that independent position verification of the valve in its prescribed position last had been performed on April 6, 1994, prior to performing the special test, and concluded that no independent verification of valve position had been performed during the test or prior to EDG operability being required on May 3, 1994. The valve lineup verification form was changed and valve 1-DGCW-7 was independently verified in the new (open) position on May 4, 1994. This is the second example of the **violation** of the independent verification requirements specified above.

After being informed by the inspector of the discrepancies discussed above, the licensee performed independent verification of the valves in their proper positions. The licensee also reviewed valve lineup sheets for safety systems for which independent valve position verification was previously completed and on which special procedures subsequently had been conducted, and independently verified the positions of valves identified by the review as having been manipulated. No further valve position discrepancies were found. The inspector concluded that the licensee's initial corrective actions were adequate. In a discussion with the Operations Manager on May 11, the inspector expressed a general concern regarding manipulation of valves in safety-related systems without proceduralized controls, and noted that significant events, including an inadvertent reactor coolant system draindown, had occurred at Unit 2 in late 1993 due to a similar lack of formality. (See NRC Inspection Report 50-336/93-11) The Operations Manager acknowledged this concern but had not developed a plan for action to prevent recurrence for the two instances discussed above. Notwithstanding the immediate corrective actions discussed above, these two

examples of poor configuration control will be cited as a **violation** of Technical Specification 6.8.1.a. because the examples were NRC-identified, the concern with configuration control has more than minor safety significance, and the problem could have been prevented as a result of similar events involving poor configuration control. **(VIO 245/94-18-01)**

2.3 Valve Design Deficiency Identified - Unit 1

On May 10, 1994, the licensee informed the NRC that two valves in the main steam system and two valves in the main feedwater system may not have been operable under all design conditions during previous cycles of plant operation. The valves might not have moved to the required safety position under full design differential pressure. The licensee classified the issue per 10 CFR 50.72(2)(iii)(D) as an event or condition that alone could prevent the mitigation of the consequences of an accident. The deficiency was discovered when the licensee was conducting a review of valve design criteria as required by NRC Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." During the review, the licensee determined that all four valves could require a valve friction factor of 0.6 to operate under all accident conditions. However, these four valves had a friction factor of less than 0.4.

The valves of concern are the main steam isolation valve (MSIV) bypass valves, 1-MS-5/6; and the feedwater block valves, 1-FW-4A/4B. The bypass valves are used to heat the main steam piping that is located downstream of the MSIVs and equalize pressure across the MSIVs before they are opened during a plant startup. Once the main steam lines are warmed and the MSIVs are open, the bypass valves are closed. The bypass valves receive a signal to go closed on a Group 1 isolation signal. When reactor power is above ten percent, one or both of the feedwater block valves are open to supply reactor feedwater. Above 50 percent power, both block valves are open because both feedwater strings are needed to support operation. The block valves are part of the feedwater coolant injection (FWCI) system and receive a signal to open on receipt of an emergency core cooling system (ECCS) actuation, to allow water from the FWCI system to enter the reactor vessel.

Licensee corrective action consisted of increasing the valve factor to 0.6 for valves MS-5/6. Valves 1-FW-4A/4B were not modified this outage. Rather, the licensee modified station procedures to ensure the block valves remain in the open (accident) condition when the FWCI system is required to be operable. The licensee is evaluating several options to restore full operability to the feedwater block valves during the 1996 outage. Some of the options include changing the internal valve guides from a carbon to stainless steel material or modifying the valve gear ratio.

The inspector noted that valves 1-MS-5/6 and 1-FW-4A/4B are normally in their accident position during power operation thus minimizing the risk associated with these discrepancies. The inspector verified the licensee's interim corrective action for the feedwater block valves was acceptably implemented.

2.4 Nonconservative Setpoints for the Average Power Range Monitor High Neutron Flux Trip and Rod Block Safety Functions - Unit 1

On July 28, 1994, at approximately 11:30 a.m., with the reactor at 39% power, the licensee identified that the reactor protection system setpoints for the average power range monitor (APRM) flow-biased high neutron flux reactor scram and control rod block functions (limiting safety system settings) had not been reduced as required by the technical specifications (TSs) when the maximum fraction of limiting power density (MFLPD) exceeded the fraction of rated power (FRP). By 11:50 a.m., selected control rods were manipulated in the reactor to reduce the MFLPD to an acceptable value. The licensee notified the NRC of the condition per 10 CFR 50.72 at 1:29 p.m.

The APRM high neutron flux scram insures fuel cladding integrity by causing automatic protective action before the minimum critical power ratio (MCPR) safety limit is violated. This assures the margin to the transition boiling region is maintained. The control rod block provides additional margin against violation of this safety limit. Six APRM instrument channels (three channels per scram trip system) generate average core thermal power signals which are conditioned by reactor recirculation (coolant) flow signals to produce flow-biased outputs to the reactor protection and APRM rod block systems. Technical Specifications (TS) 2.1.2.A.1.b (scram) and 2.1.2.B.1.b (rod block) define the APRM instrument channel limiting safety system settings, and state that when MFLPD exceeds FRP, the scram and rod block settings must be modified by a multiplication factor consisting of the ratio of actual FRP to MFLPD.

Unit 1 TS 3.1.A, Table 3.1.1, "Reactor Protection System (Scram) Instrumentation Requirements," requires a minimum of two APRM channels per trip system to be operable, whenever the mode switch is in the RUN position, with flow-biased neutron flux trip level settings per TS 2.1.2.A. If the minimum number of channels per trip system cannot be met for both trip systems, this limiting condition for operation (LCO) requires either that all control rods be completely inserted into the core within four hours, or that reactor power be reduced to the intermediate range and the mode switch placed in the Startup/Hot Standby position within eight hours. For the APRM rod block function. Unit 1 TS 3.2.C, Table 3.2.3, "Instrumentation That Initiates Rod Block," requires a minimum of one APRM channel per trip system to be operable with trip level settings per TS 2.1.2.B, or the systems shall be tripped.

On July 27, reactor power had been reduced to less than 40% to comply with the TS action statement for an inoperable isolation condenser. Per TS 4.1.B, the MFLPD is checked and the APRM scram and rod block settings are determined to be valid only once daily, and the operators had verified that the MFLPD was less than the FRP just prior to reducing reactor power. However, shortly after the power reduction, at approximately 10:30 a.m., MFLPD exceeded the FRP, and the condition persisted, unnoticed by the operators, until approximately 11:30 a.m. on July 28, when a reactor engineer identified the discrepancy.

The reactor engineer noted the excessive value of MFLPD and directed the operators to insert control rods to restore the MFLPD-to-FRP ratio to less than 1.0. This action was completed at 11:50 a.m.

Inattention to the MFLPD limit by operators and reactor engineering resulted in failure to modify the nonconservative APRM instrument trip settings in a timely manner. Thus, the limiting conditions for operation of TS 3.1.A and 3.2.C were exceeded for approximately 21 hours for the scram settings and 25 hours for the APRM rod block settings. This is a **violation** of TS requirements regarding the APRM instruments. In addition, upon identifying that the TS limiting safety system setting requirements of the APRM instruments were not met on July 28, the operators did not declare the instruments inoperable and implement the action statement requirements of TS Table 3.2.3.

Per procedure OP-204, "Power Operation," a reactor engineer was called to the control room to monitor core parameters during the power reduction. The reactor engineer is responsible for determining whether the reactor is operating with a limiting control rod pattern. However, the engineer left the control room before the MFLPD deviated from an acceptable value and did not exercise this responsibility effectively. However, the responsibility for ensuring that the reactor is operated within the safety limits and conditions established by the TS resides primarily with the licensed operators. The values of MFLPD and APRM power are displayed continuously on plant process computer terminals in the control room, yet several crews of operators failed to recognize the deviant condition which was displayed. Also, the formal shift turnover process established by procedure OP-696.1, "Control Operators Log," does not include review of core thermal limits. The inspector concluded that the licensee's control of the APRM high neutron flux level limiting safety system settings by the operators and reactor engineering were not effective.

Per the Unit 1 TS bases, accident analyses demonstrate that with a fixed scram trip setting of 120%, none of the postulated transients result in violation of the MCPR safety limit, and that there is substantial margin to fuel damage. The flow-biased scram trip setting provides additional margin. The rod block trip limits the gross reactor power increase from withdrawal of control rods in the normal withdrawal sequence, providing further margin from the MCPR safety limit. The inspector calculated that the nonconservativism of the APRM high neutron flux level scram and rod block trip settings had varied from four to fifteen percent of reactor power during the 25 hour period. The actual MCPR safety limit would not have been approached during this occurrence because of the large margin that exists in the safety analyses. Thus, the safety consequences of reactor operation with unmodified trip settings were mitigated by the large margins factored into the TS requirements. Nonetheless, operation with nonconservative scram and rod block trip settings resulted in an unacceptable reduction in the margins to fuel cladding safety limits. In addition, the ineffective controls over limiting safety system settings was significant.

In response to the event, the licensee removed the responsible reactor engineer from on-call duties and changed procedure OP-204 to augment the guidelines for monitoring core safety

limit parameters following power maneuvers. The licensee also initiated a review of the event through its plant information report process. The **violation** of TS requirements concerning inoperable APRM flow biased high neutron flux scram and rod block functions will be **cited. (VIO 50-245/94-18-02)**

2.5 Unplanned Engineered Safety Features (ESF) Actuation - Unit 2

During system restoration following the performance of procedure SP 2613C, "ESF System Integrated Test (IPTE)," an unplanned actuation of Facility 2 (train B) of the ESF system occurred. Unit 2 was in mode 5 during an outage to replace the 'D' reactor coolant pump seal. At approximately 7:00 a.m. on May 13, 1994, operators reset Facility 1 and 2 safety injection actuation signals (SIAS) in accordance with the procedure by pressing the "SIAS RESET" buttons on the ESF actuation cabinets, and immediately noted a Facility 2 ESF actuation. Several Facility 2 loads started, including the 'B' coolant charging pump, and the boric acid pumps. This resulted in a small amount of charging flow to the cc.e from the boric acid tanks. The ESF actuation was terminated by operators and did not result in any complications. The unplanned ESF actuation met licensee criteria for an Unusual Event. The event was properly classified, and appropriate notifications were made.

The licensee preliminarily concluded that the most likely cause of the unplanned ESF actuation had been a spurious signal, caused by the electrical noise generated by simultaneously resetting over 30 relays in the Facility 2 ESF actuation cabinet. Relay noise is a previously identified problem in the ESF cabinets, for which the licensee has prepared a modification to install noise suppression diodes in each relay circuit during the upcoming refueling outage. Based on this preliminary information, the management test lead (MTL) for the test procedure recommended continuing with the test, and performing troubleshooting activities at a later time, as the remainder of the test did not impact the ESF system. At the morning management meeting wherein the test discrepancies were discussed, plant management endorsed the MTL's recommendation and concurred with proceeding with the ESF test. However, the inspector raised concerns that the "termination criteria" for the ESF test had apparently been met by the unplanned ESF actuation, and the procedure required that the test be terminated, plant conditions stabilized, and the cause of the actuation investigated. After further evaluation of the test termination criteria by licensee management, the test was terminated at 9:00 a.m.

Procedure SP 2613C had been carefully planned in accordance with the guidelines of administrative procedure ACP-QA-2.27, "Infrequently Performed Tests and Evolutions (IPTE)." IPTE requirements provide heightened management sensitivity to these tests, and include additional management oversight and controls due to the potential for affecting reactor safety, damaging plant equipment, or decreasing personnel safety. Management had not been made aware of the termination criteria, applicable contingency actions, and restart requirements listed in Attachment 3 to the procedure, during discussions that followed the unplanned ESF actuation. Therefore licensee management's decision to continue with the test was based on incomplete information, and would have required revising the existing

procedure requirements. The licensee would have continued with procedure SP 2613C without making these procedure changes. Without NRC intervention, the licensee would not have met the requirements specified in the termination criteria of Attachment 3 to procedure SP 2613C, and may have compromised the planning and controls established in this IPTE. The Unit Director stated that these issues would be specifically addressed in the response to the plant information report (PIR) covering this incident. This issue remains **unresolved** pending NRC review of licensee corrective actions. **(UNR 336/94-17-03)**

2.6 Rupture of Main Condenser Waterbox - Unit 3

On April 29, 1994, with the plant operating at full power, the plant experienced a circulating water (CW) transient which ruptured one of six condenser waterboxes at the CW outlet of the main condenser. The leak resulted in flooding of the CW pit to a depth of about two feet. Operators were alerted to the event by the condenser pit high level alarm. Operators noted condenser vacuum decreasing and an increased 'E' CW pump amperage, and promptly isolated the ruptured waterbox within five minutes. The condenser is designed to operate satisfactorily at full power with one waterbox isolated. The plant remained at full power and did not approach the condenser low vacuum main turbine trip.

The licensee formed a task team to determine the cause of the event, evaluate the necessary recovery actions, and make the necessary system repairs. The licensee's investigation determined that the power valve operator for the 'E' waterbox CW discharge valve, 3CWS-MOV27E, separated from the valve stem allowing the 84-inch butterfly valve to slam shut causing a pressure transient. The licensee's preliminary calculations revealed that the CW pressure in the 'E' outlet waterbox increased to approximately 600 psi; system design pressure is 50 psi. The resultant transient ruptured the 'E' CW outlet waterbox (two 6 foot x 4 inch tears in the area of previously welded seams).

Upon disassembly of the CW discharge valve the licensee discovered that the setscrew holding the spline adapter to the valve stem was loose and the pin which limits the travel of the spline adapter had previously been sheared off. Since the valve stem is in the vertical position, the spline adapter could drop down on the valve stem, thus disengaging from the stationary drive sleeve. The licensee had experienced a similar problem with the 'E' condenser outlet valve on January 10, 1994. The valve operator to stem interface was found disconnected during investigation of a leak on the 'E' inlet manway. The licensee's corrective action for that event involved repairing the leaking manway and staking the spline adapter back into place. The licensee did not tighten the setscrew or reinstall the pin since the manufacture's drawing did not indicate the presence of these design features. The licensee has not determined why the drawings did not indicate the pin or setscrew. The licensee's investigation of this prior incident focused on the cause of the leaking manway, and concluded that the valve stem/operator separation did not cause the manway leak since there had been no indication of low flow through the condenser prior to stopping the CW pump.

As corrective action for the April 1994 event, the licensee installed a locking setscrew for the 'E' CW discharge valve, reinstalled the pin, and developed a plant design change to install a spline support plate on the top of the spline adapter to limit its travel in the event the setscrew becomes loose. A drawing change notice has been initiated to modify the manufacture's drawing to document the methods used to hold the spline adapter in place. In addition, the licensee verified that pins were installed on the other CW discharge valves and other butterfly valves in the CW system with the same orientation. A walk down of the 'E' CW pump piping and associated components revealed no additional damage. The licensee inspected electrical equipment in the sprayed area and identified no problems. The licensee tested all pressure sensitive instruments that may have been affected by the event prior to placing the 'E' CW pump back into service. Magnetic particle inspections of the 'E' condenser waterboxes revealed other indications (cracks), which were adequately dispositioned, on the interior of the inlet and outlet waterboxes. The fit up and weld repair of the outlet waterbox tears were completed. The licensee also issued a memorandum to all station personnel and the engineering manager has briefed the engineering department on the need to recognize, evaluate, and correct deficient conditions when problems initially present themselves.

The inspector considered the operators' response to the April 1994 event and the licensee's recovery action plan to be very good. However, the inspector considered the investigation of the January 1994 event to be too narrowly focused on the repair of the manway leak and had not adequately characterized the causal relationship of the valve stem/operator separation.

3.0 MAINTENANCE (IP 62703, 61726)

The inspectors observed and reviewed selected portions of preventive and corrective maintenance and surveillance tests, and reviewed test data to verify: adherence to regulations, administrative control procedures and technical specification limiting conditions for operation; proper removal and restoration of equipment; appropriate review and resolution of test deficiencies; appropriate maintenance procedures in use; adherence to codes and standards; proper QA/QC involvement; proper use of bypass jumpers and safety tags; adequate personnel protection; and, appropriate equipment alignment and retest. The inspectors reviewed portions of the following work activities:

- M1-94-06652 Overhaul valve 1-LP-9B
- M1-94-07132 Install T-drain in motor operator for valve 1-RR-2A
- M3-90-22666 Calibrate charging pump P3B, lube oil pressure switch, 3 year PM
- M3-92-08451 Calibrate diesel jacket water heater 3EGS*TS31B
- M3-94-00310 Repair RHR*P1B 4160 breaker clutch mechanism
- M3-92-08600 Clean, inspect, and test MCC starter for primary grade water storage tank heater 3PGS-E1A
- M3-94-03115 Replacement of service water piping due to pinhole leakage
- M3-94-07969 Disassemble, inspect 'A' diesel air start control valve 3EGS*ASU2A

- M3-94-09446 Remove, replace diaphragm and 0-ring to 'A' diesel cooling water jacket water temp control valve
- OP 3310B Accumulator low pressure safety injection
- OP 3670.2 Technical specification related PEO rounds
- SP 3626.9 Control Building Air Conditioning Booster Pump P2B, Operational Readiness Test
- SP 3630E.1 'A' Safety Injection Pump Operational Readiness Test
- SP 3622.3 Auxiliary Feedwater Pump P2 Operational Readiness Test
- SP 3541A12 Seismic Monitor Channel Check
- SP 412K LPCI/Containment Cooling System Logic Test
- SP 623.16B Personnel Airlock Doors Seal Leak Rate Test at 43 PSIG
- SP 681 Operational Leak Test of Reactor Vessel (IPTE)

Except as noted below, the inspectors determined that the maintenance and surveillance activities observed were performed adequately. Details of the inspector's observations are provided in Sections 3.1 to 3.4.

3.1 Inadvertent Reactor Vessel Draindown During Logic Testing - Unit 1

3.1.1 Event Summary

On April 10, 1994, during the performance of a surveillance procedure that tests the low pressure coolant injection (LPCI) system loop select logic in accordance with procedure SP 412K, "LPCI/Containment Cooling System Logic Test," reactor vessel water was inadvertently discharged into the drywell through the drywell spray header. The event was caused by the inappropriate combination of two previously performed surveillance tests and an ineffective procedure review and approval process. Operators who had some opportunity to recognize the flawed procedure methodology did not recognize the significance of the ongoing test activity, and therefore did not question the degrading system alignment. The spray down lasted approximately 5 minutes. During that time period, the licensee estimated that about 12,000 gallons of water was diverted from the shutdown cooling system into the drywell. Reactor vessel water level decreased from 83 to 6 inches as read on the vessel floodup level indicators. The event was terminated when operators closed valves in the LPCI system, which isolated the draindown path. Had the operators failed to take this action, emergency core cooling actuation would have occurred at the reactor vessel low level setpoint; and that failing, shut down cooling would have isolated at the two thirds core coverage interlock setpoint. Both of these back-up methods would have terminated this event.

The licensee classified the event as an Unusual Event and made appropriate notifications to the NRC and State and local officials. NRC review of the event included an examination of the licensee's procedure review and development process, an analysis of the operator

performance prior to and during the event, an evaluation of the licensee recovery of the drywell and associated equipment that was wetted by reactor coolant, and an assessment of the licensee's root cause analysis and corrective action for the event.

3.1.2 Procedure Development, Review and Approval Process

During the performance of surveillance procedure SP 412K, the Unit 1 reactor vessel level was inadvertently lowered through the drywell spray system. Approximately 12,000 gallons was sprayed into the drywell because the approved procedure aligned the systems to create this unintended consequence, and neither the procedure review nor approval process identified that error. The licensee stopped the test, stabilized the reactor inventory, and formed an Event Evaluation Team (EET) to investigate the event. The licensee concluded that two well-established procedures had been combined into one procedure, and the procedure review and approval process lacked the rigor to assure that such procedure changes do not create new undesired consequences. The licensee suspended all integrated plant testing, and committed to the NRC to review all remaining integrated test procedures prior to performing these tests. As a result of telephone conference calls between NRC and the licensee regarding the event sequence and projected Unit 1 followup activities, the licensee docketed a description of the event and their intended response activities in a letter to NRC dated April 11, 1994.

An interim test procedure review process was established by the EET. The EET performed an initial screening of all remaining tests and surveillance procedures against established criteria. For instance, all complex or inter-system testing, as well as first time tests were held for further review, while routine and single system tests were released to operations. Tests needing further review were then sent to a multi-disciplined technical review group to verify that the procedures could be safely executed, resulted in the expected plant response, and were enveloped by applicable safety evaluations and shutdown risk reviews. The technical review group then forwarded each test or surveillance procedure to the Plant Operational Review Committee (PORC) for approval, after all comments had been resolved. The PORC reviewed each procedure and provided final approval following resolution of all comments. A list of all test and surveillance procedures, which had been through the test procedure review process and were released for testing, was updated daily and provided to the operators. Procedures which did not appear on this list were not authorized to be performed by the operations staff.

The inspector evaluated various aspects of the licensee's interim measures to ensure integrated testing could be performed in a safe manner. The inspector independently verified that procedures which had met the screening criteria were forwarded to the technical review group for an in-depth review. The procedure review group was first re-acquainted with plant guidelines for infrequently performed tests and evolutions (IPTE), and the shutdown risk management program. The group used P&IDs, basis documents, and other applicable reference material during their procedure reviews, and the procedure writers were brought in, when possible, to provide amplifying information. Inspector observations of the

procedure review group during procedure reviews confirmed that a multi-disciplined group was conducting extremely thorough reviews of every step of each procedure. The group's comments were documented and forwarded to the applicable procedure writer for resolution.

The inspector performed in-depth evaluations of selected test procedures, including the procedure review process and the actual performance of the tests. Test procedures evaluated included: procedure SP 628.1, "Integrated Simulated Automatic Actuation of FWCI, Core Spray, LPCI, Diesel and Gas Turbine (IPTE);" procedure SP 412K, "LPCI/Containment Cooling System Logic Test;" and procedure SP 627.7, "Isolation Condenser Primary Side Hydrostatic Test." The inspector noted that the procedures received a detailed review by the multi-disciplined technical review group and PORC members. The procedures were performed without incident, and the inspector concluded that the interim test procedure review process provided reasonable assurance that the remainder of the integrated testing during this outage would be conducted in a safe manner.

The licensee also committed in their April 11, 1994 letter to determine the inadequacies in the procedure review process which contributed to this event. The EET determined that the procedure review process and other available operational controls such as IPTE and shutdown risk, provided the appropriate barriers to assure that procedures were accurately prepared and implemented. However, the formal process provided such latitude as to which barriers to apply, that in the case of procedure SP 412K, the appropriate barriers were either omitted or not carefully carried out.

Technical Specification (TS) 6.8.2 requires Unit 1 procedures to be reviewed by the Plant Operations Review Committee (PORC) and approved by the Unit Director in order to assure that careful multi-disciplined reviews are conducted for significant plant procedures. The inspector concluded that, in the case of Revision 10 to procedure SP412K, this TS required barrier was not effectively implemented. In order to address this finding following the disbanding of the EET, the licensee implemented interim administrative controls on May 16, 1994. These controls require a similar screening of all procedures brought to the PORC, and require management to rigorously review the need for implementation of additional measures to assure the accuracy and correct implementation of significant procedures. These controls remain in effect pending the licensee's implementation of a formal assessment of the site-wide procedure review and approval process, and completion of long-term corrective actions to prevent recurrence. The licensee committed to complete these actions in July 1994. Based on the self-disclosing nature of this event, the minimal safety consequences of the reactor vessel draindown, and the comprehensive corrective actions planned and completed, the inspector determined that the failure of the PORC procedure review process meets the criteria for exercise of discretion in accordance with Section VII.B of the NRC Enforcement Policy. Therefore, this violation will not be cited. The satisfactory completion of procedure review program changes will be followed by **open** item **IFI 245/94-18-04**.

3.1.3 Operator Performance

The shift supervisor authorized the conduct of procedure SP-412K on April 10, 1994. A licensed operator was assigned to conduct the evolution with instrumentation and control technicians. There was an additional on-shift reactor operator monitoring plant activities. No shift briefing or detailed review of the test procedure was conducted by the operations department, because the operators believed this test to be a routine logic test with no operational consequences. During the conduct of the test, the operators and technicians followed the procedure as written, until the reactor vessel drain down event was apparent. Upon receipt of the drywell sump level alarm, the cause of the event was promptly identified and the leak path was isolated.

During NRC review of this event, the inspector learned that the operating crews had received training on prior reactor vessel drain down events during shutdown operations. This training was conducted just prior to this outage in response to several industry experience references to prior events at other plants. The inspector concluded that although the operators had followed the existing procedures, there was a general lack of attention to changes in plant configuration which the surveillance procedure called for. This lack of attention apparently resulted from the operating staff assumption that this was a benign logic test. However, a more questioning approach by operations supervision in approving the evolution and by the operators conducting the logic test could have recognized the flawed procedure and prevented this transient.

The event evaluation team (EET) recognized that procedure SP 412K was not implemented with a level of oversight and control commensurate with the potential system interactions involved with this evolution. This observation was strengthened by a Unit 1 Nuclear Review Board (NRB) special assessment of this event which concluded that weaknesses in procedural usage contributed to this event. Specifically, personnel awareness of and responsibility for the impact of individual procedure steps and shift management assurance of a team approach to integrated testing need to be enhanced. The Operations Manager provided interim counseling for operators in this regard prior to plant start-up from the refueling outage. NRC review of the operator performance issues highlighted by this event will remain **open** pending completion of licensee evaluation and long term corrective action for the findings of the EET and NRB review team reports. **(IFI 245/94-18-04)**

3.1.4 Post-Drywell Spray Event Restoration - Unit 1

Following the reactor vessel draindown/drywell spray event which occurred on April 10, 1994, the licensee developed and implemented a drywell restoration plan which included inspection and functional testing of the electrical and mechanical equipment which potentially was affected by water intrusion. Inspections were performed of all motors, valve motor-operators, solenoid-operated valves, instrumentation, containment electrical penetrations, and cable trays and conduits. Insulation resistance checks were performed on the motors, and the motor-operated valves were functionally tested. No unacceptable conditions attributable to

the event were identified, and no safety-related equipment was adversely affected. The licensee also inspected satisfactorily the drywell air coolers, drywell-to-torus vacuum breakers, and mechanical and hydraulic snubbers. The affected train containment spray header nozzles were air tested to ensure that no fouling had occurred. The licensee also verified through visual inspection and chemical analysis that conditions in the torus and the torus ring header were acceptable. Pipe insulation was tested for leachable fluoride and chloride contamination levels and found to be within the acceptance criteria established in Regulatory Guide 1.36, "Nonmetallic Thermal Insulation For Austenitic Stainless Steel."

The inspector found the licensee's restoration plan to be comprehensive. Inspection and test results were documented fully in automated work orders, a sample of which were reviewed by the inspector. No discrepancies were identified. The inspector also toured the drywell on several occasions following the event and verified that the licensee's cleanup efforts were adequate. The inspector concluded that the licensee's corrective actions regarding material conditions within the primary containment were acceptable.

3.1.5 Root Cause Assessment

The EET evaluated all aspects of the Unit 1 drywell spraydown event, identified the causes and contributing factors for the event, and provided a number of recommendations to address these causes. Additionally, a global oversight of the event was provided by a Nuclear Review Board (NRB) Oversight Review Team. Although the EET's efforts were quite extensive, the NRB team identified additional areas of concern, and also provided a number of recommendations.

The inspector independently evaluated the RPV level transient, identifying four significant causes for the event: (1) inadequate procedure review process; (2) inadequate Plant Operations Review Committee (PORC) review and approval process; (3) inadequate screening criteria for Infrequently Preformed Tests and Evolutions (IPTE); and (4) inadequate operator reviews and approval of an activity affecting plant operations without fully understanding its effects. The inspector noted that overall, the licensee's combined investigation of the event was good; however, although all major areas of concern were identified, many of the corrective actions recommended are too general in nature (i.e broad changes to programs or procedures without specific details, or recommendations for further evaluation of an identified problem area). The effectiveness of licensee corrective actions will be followed by **open** item **IFI 245/94-18-04**.

3.1.6 Conclusion

The reactor vessel draindown/drywell spraydown event occurred because the procedure was poorly developed and inadequately reviewed and approved. Operators followed the procedure as written, but could have stopped the event had they assessed the affects of the procedural steps/sequences. The licensee's initial response to the event, including operator response, management control of the event response and resumption of outage activities, and

drywell cleanup and equipment verification were conducted in an outstanding manner. The causal analyses conducted following the event were comprehensive and reached good conclusions. Many of the corrective actions had not been sufficiently developed to provide assurance that all of the causal factors will be corrected.

3.2 Inadvertent Emergency Core Cooling Actuation Due to Personnel Error - Unit 1

On April 8, 1994, while performing post-installation testing of a modification, Unit 1 test personnel inadvertently initiated portions of the emergency core cooling systems (ECCS). Operator response to the event included stopping the pumps which had started and repositioning valves, as necessary. No water was injected into the reactor vessel. The licensee informed the NRC of the engineered safety features (ESF) actuation per 10 CFR 50.72(b)(2)ii.

The post-installation testing was being conducted to verify that the drywell recirculation fans would automatically go into a variable speed mode of operation when the pressure in the drywell reached two psig, and trip off when pressure reached five psig. Prior to installation of the modification, when drywell pressure increased to the two psig setpoint, operator action was required to place the drywell fans into the variable speed mode of operation. Post-installation testing of the modification was conducted through use of special procedure SP 1-93-28, "RBCCW Isolation and Drywell Cooler Trip Logic Testing." The procedure tested the newly installed drywell cooler logic, by simulating an increase in drywell pressure and verifying the expected drywell cooler response. To prevent an actual ESF initiation during the testing, procedure SP 1-93-28 required sleeving the contact fingers of various General Electric HFA relays. The HFA relays at Unit 1 contain twelve contact fingers that can be open or closed depending on the application in which the relay is used. During the sleeving process, testing personnel did not sleeve the proper contact fingers specified in the procedure. The ESF actuation occurred when a simulated signal was generated and was not blocked by the proper sleeving of relay contacts.

When the ECCS signal was generated, the low pressure coolant injection system pumps started, the core spray injection valves opened, the recirculation system valves repositioned and the gas turbine and diesel generator received a start signal. Several components in the LPCI and CS system did not start since their power supplies had been removed. According to the licensee, a complete ECCS actuation did not occur because the test signal was not input at a location that would energize the complete ECCS system logic matrix. Following the ECCS initiation, licensee personnel verified that all components that should have operated due to the input signal did operate as required.

The inspector reviewed the steps of the procedure which were incorrectly followed. The inspector noted that steps 6.2.10 and 6.2.11 stated that sleeves should be installed over contacts one through six of relays 108 and 109, respectively. Both steps required dual verification that the sleeves were properly installed on the specified contacts. However, during the test, personnel sleeved contacts seven through twelve of the relays. Although the

individual HFA relay contact fingers are not numbered, test personnel stated that the relay contacts are typically numbered from right to left. The test personnel were not able to explain why they sleeved the incorrect contacts. The licensee's root cause analysis determined that the test procedure lacked sufficient detail to assure that the proper contacts were sleeved.

The inspector concluded the inadvertent ECCS actuation was caused by personnel and procedure error. Test personnel did not adequately perform, nor carefully verify the procedural steps as written. Although a more detailed description of the HFA relay configuration may have assisted the technicians in performing the contact sleeving properly, a more diligent implementation of existing procedure steps would have prevented the event. The procedure was changed to provide a more detailed description of the contact configuration and the procedure was rerun satisfactorily.

The inspector attended the post-event critique that was assembled per procedure ACP-QA-10.15, "Post-Trip and Transient Review." The test personnel who had made the sleeving error, also did not have a complete understanding of the event. Specifically, at the meeting, the test personnel stated that the LPCI pumps did not start since their power supply had been removed prior to the event. However, the four LPCI pumps did start when the test signal was generated. No further significant observations were made concerning the event review team.

The failure to sleeve the correct contacts was a procedural violation. Based on the self-disclosing nature and low safety significance of the event, and the corrective actions planned and implemented by the licensee; the inspector determined the criteria for enforcement discretion listed in Section VII.B of the NRC Enforcement Policy were met. Therefore, this violation will not be cited.

3.3 Engineered Safety Features Actuation Due to Maintenance Error - Unit 1

On April 22, 1994, an inadvertent engineered safety features (ESF) actuation signal was generated when an instrumentation and controls (I&C) technician caused a voltage decrease on the instrument AC electrical system. The voltage decrease caused containment isolation system groups 2, 3, and 5 to isolate, which caused a momentary loss of reactor shutdown cooling. In response to the event, operators reset the system isolation and restored reactor shutdown cooling flow. During the time that shutdown cooling was lost, reactor vessel temperature increased approximately 2 degrees Fahrenheit. The licensee reported the inadvertent ESF signal to the NRC as required by 10 CFR 50.72(a)(2)(ii).

The voltage dip occurred when the I&C technician moved an alarm panel cover into contact with a fuse block [illegible] instrument AC system while working on an electrical module in the adjacent steam leak detection system panel. This caused a short circuit. According to the licensee, the technician could not remove the cover from the work area since it was connected to the alarm panel by a wiring harness. Although the electrical short caused a fuse

to blow, subsequent checks of the components on the instrument AC system did not identify any other discrepancies. Short term corrective action consisted of modifying the back panel of the steam leak detection system so the alarm panel cover could be completely removed from the area when access to the steam leak panel is required.

When reviewing the event, the inspector had concerns regarding the scope of the licensee review and followup to the inadvertent ESF actuation. Specifically, the licensee did not attempt to verify that all the actuations that would be expected to occur when the instrument AC bus was lost had occurred. For example, licensee personnel initially could not explain why the standby gas treatment (SBGT) system did not actuate when instrument AC voltage decreased. Additionally, licensee personnel did not fully utilize procedure ACP-QA-10.15, "Post-trip and Transient Review," when investigating the cause of the ESF actuation. Licensee personnel determined that since instrument AC voltage was never completely lost during the short, it would be difficult to determine which systems should actuate. The inspector noted that part of any investigation into an event should include an evaluation of what occurred and what should have occurred. Differences should be explained where possible. According to the licensee, procedure ACP-QA-10.15 was not used in this instance since personnel did not believe that a primary containment isolation was an ESF actuation.

The inspector noted that emergency plan implementing procedure form 4701, "Unit 1 Definition of Engineered Safety Features," states that a primary containment isolation is an ESF signal. Therefore, the inspector noted that ACP-QA-10.15 is required to be used following an ESF actuation. The procedure includes a check sheet that provides operators with guidance on what to look for following an event. One part of the check sheet requires personnel to review an event and determine which equipment actuated. If the equipment did not operate as expected, the procedure requires operators to investigate the reason. The licensee stated that personnel would be reinstructed on what systems constitute ESF actuations. Additionally, procedure ACP-QA-10.15 would be used to investigate the event.

The failure to follow the post trip guidelines listed in procedure ACP-QA-10.15 following this inadvertent ESF actuation is a violation. However, because the issue was of minor safety significance, and because adequate corrective actions were being taken by the licensee, the criteria for enforcement discretion listed in Section VII.B of the NRC Enforcement Policy were met and this violation was not cited.

3.4 Maintenance Work Performed Outside the Job Scope - Unit 3

On April 26, 1994, the inspector witnessed portions of automatic work order (AWO) M3-94-03115; replacement of a segment of service water (SW) piping per plant design change record (PDCR) M3-93-222. The piping was being replaced due to the discovery of a pinhole leak in the service water return line from the 'A' diesel generator (EDG) heat exchanger. The inspector reviewed the AWO and inspected the work site and noted that as

part of the piping replacement, air operated valve 3SWP*AOV39A had been removed and the air supply line from the solenoid to the valve had been disconnected because the valve would no longer be supported upon piping removal.

The inspector reviewed the tag clearance and noted that the air supply line to the solenoid valve was not tagged out and immediately notified the operations department work order coordinator of this finding. The work was temporarily secured and the air line tagged shut to ensure personnel safety. Upon completion of the work on April 26, 1994, the inspector reviewed the AWO and identified that removal of valve 3SWP*AOV39A was not documented in the work description or in the actual work performed section of the work order and no retest of the valve was specified as part of the maintenance activity. The inspector notified the shift supervisor and was informed that following reinstallation valve 3SWP*AOV39A had been adjusted and cycled after operators in the control room initially noted dual indication for the valve. The licensee subsequently credited this functional test as a proper retest of valve 3SWP*AOV39A following maintenance, and thus continued operability of the 'A' EDG was verified.

The inspector was concerned that the work control practices intended to protect personnel and equipment safety, and to assure adequate re-testing prior to system restoration had not been accomplished in accordance with station administrative control procedures (ACPs). The following specific activities were performed contrary to the requirements of the ACPs. The job leader/supervisor did not clearly define the job scope of actual work to be performed on valve 3SWP*AOV39A, as required by procedure ACP-QA-2.02C, "Work Orders," step 6.2.15. The job leader/supervisor failed to assure that the maintenance area isolation was adequate for work to be performed, as required by procedure ACP-QA-2.02C, step 6.6.1.1 and procedure ACP-QA-2.06A, "Equipment Tagging," step 1.5.2. The job leader also did not document in the AWO the actual work performed on valve 3SWP*AOV39A, as required by procedure ACP-QA-2.02C, step 6.6.2.

Previous inaccurate and inadequate documentation of work has occurred at Millstone Unit 3. NRC Inspection Report 50-423/92-23 discussed the inoperability of a safety-related hydrogen recombiner at Unit 3 caused by licensee failure to document that electrical leads to the blower had been disconnected. In their January 26, 1993, response to the NRC Notice of Violation for that event, the licensee stated as action to prevent recurrence that all Millstone personnel involved in the AWO process would be briefed on lessons learned, and specifically on the need for proper documentation of work and adequate review of the work complete section of AWOs prior to release to the Operations Department. The inspectors noted that the maintenance job leader performing this evolution had not received this training. He was not employed at Millstone station at the time the training was given.

The licensee took several corrective actions as a result of the April 1994 event. The requirement for accurate documentation of work was discussed with I-team, Maintenance, and Instrument and Controls personnel. The maintenance department personnel involved in the subject AWO were counseled by management. The licensee committed to enhance work

control procedures regarding expectations and the need to accurately document work performed in work orders. In addition, a human performance evaluation is being performed to identify the root cause and contributing causes to determine additional corrective actions that may be needed to prevent recurrence.

This event had minor safety significance since valve 3SWP*AOV39A had been tested prior to declaring the system operable and the air to the valve operator was isolated by the placement of the SW valve in the open position. This secured the air supply from the solenoid. The inspector reviewed plant information reports and discrepancies identified during the work observation program and noted two instances in which work was performed outside the job scope. In addition, a review of quality service department surveillance audits of completed AWOs since the implementation of corrective actions for the hydrogen recombiner event revealed that there have been eight instances in which actual work documented appeared to be outside the job scope. The inspector noted that all but two of these examples were identified in the first quarter of 1993.

Nonetheless, 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires measures to be established to assure that the cause of significant conditions adverse to quality is determined and that corrective actions are taken to preclude repetition. The inspector concluded that the actions to prevent recurrence outlined in the licensee's violation response dated January 26, 1993, were not effective in preventing this similar violation of procedure ACP-QA-2.02C. This is a **violation** of Criterion XVI. **(VIO 423/94-16-05)**. Another example of this violation is discussed in Section 6.2.4 below.

4.0 ENGINEERING (IP 37700, 37828)

4.1 Implementation Of Plant Design Changes - Unit 1

The inspector reviewed plant design change records (PDCRs) that were implemented at Unit 1 during the refueling outage to assess licensee performance regarding timely completion of administrative items such as changes to drawings and procedures. (A list of the PDCRs reviewed is included in Attachment 1 of this report.) The inspector noted improvement in the overall quality of the modification packages and in the implementation of associated administrative changes. No deficiencies were found regarding changes to the "Operations Critical" drawings which are maintained in the control room. However, the inspector identified several problems concerning changes to procedures and forms, including:

- PDCR packages did not identify for review by the Plant Operations Review Committee (PORC) all of the procedures which required revision.

- Some procedures and forms were not revised prior to engineering release for operation.

- Revisions to procedures and forms were not complete.

- A surveillance procedure was not changed prior to the scheduled performance date.

10 CFR 50, Appendix B, Criterion V, requires that activities affecting quality be prescribed by and accomplished in accordance with written instructions, procedures, and drawings. Administrative Control Procedure ACP-QA-3.10, "Preparation, Review, and Disposition of Plant Design Change Records," was established by the licensee pursuant to this requirement, and contains detailed instructions for implementing design changes at Millstone. Step 4.14 of the ACP requires that station procedures be updated to reflect modifications before engineering release for operation, with the exception that step 4.16.2.1 allows surveillance procedure changes to be implemented before the next surveillance interval falls due. Contrary to these requirements, the following deficiencies indicated that additional management attention to accurate and timely implementation of PDCR administrative requirements is warranted:

PDCR 1-25-93 involved relocation of a data point from reactor pressure recorder 640-27 to recorder 640-28 on panel CRP 905, and was released for operation on April 26, 1994. The PDCR also installed a new isolation condenser data recorder (L/T/PR-1340) in panel CRP 903. The recorder was released for operation on April 13, 1994. The inspector found that the plant engineer submitted procedure changes for these modifications to the Operations Department on March 24, 1994. However, control board annunciator alarm response procedures (Form 903 A-2, window 6-4 (reactor pressure); and windows 4-4 and 7-3 (isolation condenser), were not approved by the PORC until May 3, 1994. In addition, procedure OP-307, "Isolation Condenser System," step 5.3.4, was not changed to reflect the modification.

PDCR 1-70-93 installed check valves in the emergency diesel generator (EDG) cooling water system supply and return lines to eliminate a cross-flow condition through the air intake heat exchanger during diesel operation. The modification changed the normal position of EDG cooling water system valve 1-DGCW-7 from "closed" to "open." Operations Form 338-1, "Standby Diesel Generator Valve Lineup," did not contain this change, and the PDCR was released for operation on April 14, 1994. On May 2, the inspector identified the discrepancy to the licensee, who promptly revised the valve lineup form.

PDCR 1-58-93 replaced service water and emergency service water system strainer differential pressure switches and removed six local pressure indicators. The PDCR was released for operation in a memorandum dated April 29, 1994, which stated that surveillance procedure SP-623.19, "Emergency Service Water System Operational Readiness Test," would be revised to add new acceptance criteria based on system testing. However, the procedure was not listed as requiring revision in the administrative impact section of the PDCR package. On May 25, 1994, the first

interval in which performance of the surveillance fell due, operators identified that step 6.5.7 of the procedure had not been changed to reflect the removal of service water strainer inlet pressure indicator PI-4-46. The operators promptly initiated a procedure change prior to continuing with the test.

The examples of licensee failure to update procedures prior to engineering release of the systems for operation discussed above, collectively represent a **violation** of 10 CFR 50, Appendix B, Criterion V, and of Steps 4.14 and 4.16.2.1 of procedure ACP-QA-3.10. In evaluating the criteria for enforcement discretion, the inspector noted that similar failures of design control requirements at Unit 2 were documented in NRC Inspection Report 50-336/92-36. That violation was not cited based on the licensee's comprehensive corrective actions. However, those actions were not effective in preventing the current violation. This is an NRC-identified problem that is safety significant because it affected appropriate operator response to control room alarms and because it was reasonably preventable by the previous NRC finding in this area. Therefore, this **violation** will be cited. **(VIO 245/94-18-06)**

4.2 Heat Exchanger Analysis Deficiency - Unit 1

On April 29, 1994, the licensee reported to the NRC that an analysis of the turbine building secondary component cooling water (TBSCCW) heat exchangers was inadequate in that it utilized incorrect input assumptions. The analysis of concern had been utilized by the licensee during the previous operating cycle to justify operability of the TBSCCW heat exchangers with a service water flow that exceeded the manufacturer's design value. The analysis of record to support the operability assessment incorrectly assumed the TBSCCW heat exchanger tubes were welded to the heat exchanger support plate rather than the actual rolled-in condition. Based upon this determination the licensee could not conclude that the TBSCCW heat exchangers would have remained operable with the excess service water (SW) flow for an indefinite period of time.

To correct this deficiency, the licensee rerolled the tubes during this refuel outage in a manner that could be credited by the analysis. Additionally, the licensee installed throttle valves on the outlet of the heat exchangers that would be used to limit the flow of service water through the heat exchangers to acceptable values.

The inspector considered the initial corrective action to be appropriate. However, the inspector was concerned that incorrect input analysis assumptions were utilized in an assessment that supported operability of a system. The plant manager noted the inspector's comments and stated that following startup from the current refuel outage, a review of how input assumptions are incorporated into plant analysis will be conducted. Following the review, corrective actions will be taken where appropriate. Unresolved item **(URI 245/94-18-07)** will be open pending NRC examination of the licensee's program for incorporating input assumptions into engineering analyses, and the assessment of the TBSCCW system operability during prior operation with excessive SW flow.

4.3 Outstanding Operability Issues - Unit 1

On May 6, 1994, the NRC and the licensee discussed the status of two longstanding design deficiencies at Unit 1. The first deficiency concerned the lack of seismic qualification for components that support the operability of the feedwater coolant injection (FWCI) system. The components of concern were the standby lube oil system for the condensate booster pumps and the power supplies for FWCI system area air coolers. The lack of seismic qualification for these components and the proposed licensee corrective action plan were discussed in NRC Inspection Report 50-245/94-01.

The second deficiency concerned the ability of 40 pipe supports in the low pressure coolant injection (LPCI) and core spray (CS) systems to meet code stress limits during a postulated design basis accident. This issue arose several years ago following a reanalysis of the Mark 1 torus performance following a design basis event. The reanalysis concluded that the peak torus water temperature and the resultant thermal stresses on the LPCI and CS supports could result in overall stresses greater than the Code allowed limits. The licensee's operability assessment of this issue was documented in NRC Inspection Report 50-245/91-12.

The licensee had planned to evaluate the need for modifications to restore the full qualification of the LPCI and CS components based on a safety priority ranking in the licensee's Integrated Safety Assessment Program (ISAP). However, little action to formalize the ISAP ranking for these systems had been accomplished.

During the May 6 discussion, the NRC expressed concern regarding the use of pending ISAP evaluations to delay correcting these deficiencies. Additionally, the NRC expressed a general concern regarding the length of time that operability determinations were allowed to remain in effect pending restoration of full equipment qualification. The NRC informed the licensee that the expectation of the guidance contained in NRC Generic Letter 91-18, "Information to Licensees on Resolution of Degraded and Nonconforming Conditions," was that design deficiencies dispositioned through use of an operability assessment typically should be corrected during the next outage of sufficient duration.

On May 11, 1994, the licensee provided written information concerning the current condition of the FWCI, LPCI, and CS systems and the plan to correct those conditions. The licensee stated that the existing conditions in the FWCI, LPCI and CS systems are of low safety significance since they have been demonstrated operable. In the letter, the licensee stated that their plan for the FWCI system was to utilize the provisions of 10 CFR 50.59 to relax the commitment to be seismically qualified (and submit a license amendment, if appropriate). With regard to the LPCI and CS systems, the licensee stated that the plan was to perform an ISAP evaluation to determine when the modifications should be completed.

On May 13, 1994, the NRC informed the licensee that the operability assessment that the licensee prepared to justify operability of the FWCI system without full qualification was unsatisfactory. The licensee had used a design change (FWCI not needed to respond to a

seismic event) to justify system operability without completing a safety evaluation in accordance with 10 CFR 50.59. Further, the NRC requested the licensee to ascertain if the LPCI and CS supports met design code stress limits as required by 10 CFR 50.55a.

In two letters dated May 16, and 17 1994, respectively, the licensee provided additional information concerning the FWCI support systems and the piping supports for the CS and LPCI systems. In a revised operability assessment, for the FWCI system, the licensee concluded that if a seismic event occurred, the FWCI system would still be able to perform its design function without the support systems. Further, the licensee committed to submit a timely license amendment that would formally resolve the FWCI qualification issue.

Regarding the LPCI/CS pipe stress issue, the licensee determined that although the systems were designed to the more conservative stress allowable limits of service level B criteria (system operates through and beyond moderate frequency events), the stress allowable limits of service level D (system operates through, but not necessarily beyond infrequent events) were more appropriate to the combined loading of seismic and loss of coolant accident thermal loads. Also, after reexamination of the 40 LPCI and CS system supports, the licensee determined that only 12 (rather than the previously stated 40 pipe supports) were affected by the increase in peak torus temperature. The licensee concluded that the twelve supports met service level D Code allowable stress limits. Notwithstanding this conclusion, the licensee committed to submit a detailed plan for the resolution of the LPCI and CS pipe support issues. In addition, to the extent that physical plant modifications are necessary to fully resolve these issues (upgrade the pipe supports to meet the Mark I torus design criteria (service level B stress loads)), the modifications will be completed by July 28, 1994.

The NRC reviewed the revised operability assessment for the systems and the licensee's plan for resolving the LPCI and CS supports. The revised operability assessments and the corrective action plans were determined to be acceptable. However, final review of this issue will be conducted following receipt of the licensee's detailed plan. This issue will be tracked by **unresolved item 245/94-01-12**.

4.4 Anticipated Transient Without Scram (ATWS) System Testing - Unit 2

During licensee reviews of the anticipated transient without scram (ATWS) system functional testing, the licensee identified that portions of the ATWS mitigating system actuating circuitry (AMSAC) had not been tested every refueling outage. The licensee's submittal in response to the ATWS Rule (10 CFR 50.62) dated June 27, 1988, specified that full functional testing would be performed at each refueling outage to verify the operability of the AMSAC. The licensee completed the installation of the ATWS system in 1990.

The purpose of the ATWS system is to provide a diverse scram capability for the reactor. An ATWS trip will occur when pressurizer pressure exceeds 2400 psia on two of the four pressure sensors. The energize-to-actuate logic shuts diverse scram system relays 94A/B, which trip the reactor protection system (RPS) motor generator (MG) sets' output contactors.

The MGs supply power to the control element drive assemblies through the reactor trip breakers. When the contactors open, the loss of power causes the control elements to drop into the core (reactor scram). The AMSAC system also senses reactor power, and will start the auxiliary feedwater (AFW) system after a 10 second delay if it senses both a high pressurizer pressure condition, and reactor power greater than 20%. Without an ATWS signal, the AFW system will normally start following a 3 minute 25 second delay (provided by relays 62A/B).

The licensee does not have an integrated system test for the AMSAC. Most individual components in the AMSAC are tested by various other system tests such as the pressurizer pressure functional test and the auto AFW functional test; however, the tests did not collectively test all of the AMSAC system every refueling outage. The 20% reactor power signal for AMSAC, and relays 94A/B were not tested during the 1992 refueling outage. Additionally, relays 62A/B were designated to be tested every other refueling outage. The licensee tested all portions of the AMSAC during the recent outage for the replacement of the 'D' reactor coolant pump seal. The inspector concluded that the licensee's failure to perform a full functional test of the AMSAC system during the 1992 refueling outage constituted a deviation from licensee commitments. However, pursuant to the NRC Enforcement Policy, no Notice of Deviation will be cited. The licensee has committed to develop a full functional test for the AMSAC by the next refueling outage (September 1994). This issue remains **unresolved** pending licensee implementation of corrective actions to prevent recurrence. **(URI 336/94-17-08)**

4.5 Possible Common Mode Failure of Engineered Safeguards Actuation System (ESAS) Undervoltage Modules Manufactured by Eaton - Unit 2

On May 5, 1994, during an investigation of past failures of undervoltage (UV) modules in the ESAS cabinets, the licensee determined that a possible common mode failure of the integrated circuit (IC) chip within the UV module may exist. The licensee notified the NRC, state and local officials of a condition that could have prevented the fulfillment of the safety function of a system needed to mitigate the consequences of an accident. The ESAS has four sensor cabinets, each containing two UV modules, which process an undervoltage signal from 4160 vital AC buses 24C and 24D. The ESAS logic requires 2 out of 4 UV modules to trip. The UV modules, when actuated, provide a signal to ESAS actuation cabinets which start the 'A' or 'B' emergency diesel generators (EDGs).

The IC chip on the circuit board is failing at a high rate (within 6 months to a year following installation), apparently due to a design deficiency which is causing accelerated aging. The chip is designed to last 20 years. When the IC chip within the UV module fails to a low impedance, the voltage meters for busses 24A or 24B on the respective ESAS sensor cabinet fail low, and the +15 vdc fuse in each UV circuit will fail within 0 to 18 hours. If the fuse has not blown, the UV module will function; however, the low voltage trip (106v) and

undervoltage trip (85.5v) setpoints will be degraded to some lesser values. When the fuse blows, operators receive an annunciator alarm in the control room, the undervoltage trip will not function, and the low voltage trip will be locked in.

It would take the undetected failures of three out of four UV modules per train to prevent the UV system from performing its safety function. The licensee's operability assessment of the ESAS system determined the system is operable but degraded, based on the extreme unlikelihood of six simultaneous UV module failures which went undetected. The ESAS meters are checked and recorded every shift by operators. Historically, there have been no simultaneous failures of any of the UV modules.

The licensee contacted the UV module vendor (Eaton), which subsequently notified the NRC and the licensee of the possible single failure vulnerability of their UV modules, in accordance with 10 CFR Part 21. The licensee intends to correct the UV module IC chip design deficiency during the 1994 refueling outage. The component design discrepancy report was referred to the NRC Office of Nuclear Reactor Regulation for action. The inspector noted that Millstone Unit 2 is the only plant currently supplied with these Eaton UV modules. This issue remains **unresolved** pending NRC review of the licensee's final evaluation and corrective actions. **(URI 336/94-17-09)**

4.6 Independent Safety Engineering Group Review - Unit 3

The inspector reviewed the licensee's Independent Safety Engineering Group (ISEG) activities, staffing, and impact. Nine people and one supervisor are presently assigned to ISEG. Millstone Unit 3 Technical Specifications (TS) require a minimum of four full time personnel assigned to ISEG, and specify educational and experience requirements. The present staffing is multidisciplined, and all personnel exceed the minimum experience requirements. The level of qualification in ISEG exceeds the rest of the QA organization, and contributes to a better acceptance of ISEG findings throughout the line organization. Present staffing allows some amount of ISEG effort for Units 1 and 2, but manhour allotments are driven by the TS requirement that four full time people be dedicated to Unit 3 activities. Only one evaluation was performed in 1993 which did not pertain to Unit 3, although several multi-unit evaluations which included Unit 3, as well as, one or more of the other units were done. Of the nine individuals assigned to ISEG, one is assigned to activities for each of Units 1 and 2.

The inspector reviewed several ISEG evaluations and observations and found them to be insightful. They were of high quality and a beneficial contributor to overall plant safety. A review of the nine closed recommendations completed for 1993 determined that they had been adequately addressed and implemented. Based upon the review of ISEG evaluations, the inspector concluded that ISEG met the requirements of TS 6.2.3.

An ISEG self assessment (ISEG Report E92-009) found that "a weakness in the ISEG process...is the number of recommendations that are not implemented, or are not implemented in a timely manner." Since that report ISEG began tracking implementation of recommendations originating in ISEG evaluations, and assessing the appropriateness of closeouts. It was not clear to the inspector that there had been improvement in timeliness of closeouts since the issuance of the self assessment report in September of 1992. A review of the evaluations performed in 1993 revealed that out of 41 recommendations only 9 have been closed, and for evaluations performed in 1992, 27 of 38 recommendations have been closed. In addition, two recommendations remain open from 1989 and three from 1991. As a method of tracking, and for Millstone management informational purposes, a listing of open ISEG evaluation recommendations which have exceeded their original due date is issued semi-annually. However, a more aggressive management involvement is needed to improve the timeliness of corrective actions.

5.0 PLANT SUPPORT (IP 71707)

The accessible portions of plant areas were toured on a regular basis. The inspectors observed plant housekeeping conditions, general equipment conditions, and fire prevention practices. The inspectors also verified proper posting of contaminated, airborne, and radiation areas with respect to boundary identification and locking requirements. Selected aspects of security plan implementation were observed including site access controls, integrity of security barriers, implementation of compensatory measures, and guard force response to alarms and degraded conditions. The inspectors did not identify any significant adverse plant conditions.

6.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (IP 40500, 90712, 92700)

6.1 Review of Written Reports

The inspector reviewed periodic reports, special reports, and licensee event reports (LERs) for root cause and safety significance determinations and adequacy of corrective action. The inspectors determined whether further information was required and verified that the reporting requirements of 10 CFR 50.73, station administrative and operating procedures, and technical specifications 6.6 and 6.9 had been met. The following reports and LER's were reviewed:

Units 1, 2 and 3 monthly operating report for February 1994, dated March 8, 1994
Units 1, 2 and 3 monthly operating report for March 1994, dated April 14, 1994
Units 1, 2 and 3 monthly operating report for April 1994, dated May 14, 1994.

LER 245/94-09-00 documented the failure of two hydraulic snubbers to meet the acceptance criterion for functional testing. This LER contained several administrative errors that were identified by the inspector. The errors will be corrected when the LER is resubmitted.

* LER 245/94-11-00 documented the failure of the licensee to modify the reactor vessel low level and low level setpoints as required by plant Technical Specifications when installing fuel assemblies that were a different length than what was previously installed. This issue was previously reviewed in NRC Inspection Report 50/245 94-14.

LER 245/94-12-00 documented the failure of all six safety relief valves at Unit 1 to open within the limits required by the plant Technical Specifications. This issue was previously discussed in NRC Inspection Report 50/245 94-14.

LER 245/94-13-00 reported a fifteen pound differential pressure could not be maintained across the Low Pressure Coolant Injection system heat exchangers at all times following a design basis events. This issue was previously discussed in NRC Inspection Report 50-245/94-14.

* LER 245/94-14-00 documented an inadvertent emergency core cooling system actuation due to personnel error. This issue is discussed in Section 3.2 of this report.

LER 245/94-15-00 reported an inadvertent spray down of the Unit 1 drywell during surveillance testing. This event is discussed in Section 3.1 of this report.

LER 245/94-16-00 reported a loss of special nuclear material. This issue was reviewed in NRC Inspection Report 50-245/94-19.

* LER 245/94-17-00 reported a primary containment isolation caused by maintenance error. This issue was discussed in section 3.3 of this report.

* LER 423/93-08-00 reported the inoperability of one of five electrical channels of the environmentally qualified temperature monitor for the main steam valve building for a period of approximately two weeks.

* LER 423/93-18-00 reported a condition in which a continuous fire watch was improperly removed due to improper tracking for justification of fire watches.

* LER 423/93-22-00 documented that a manual containment isolation valve was unlocked. The padlock was in place, but not securely locked.

* LER 423/94-01 discussed the inadequate performance of the overpower delta-T (OPDT) and overtemperature delta-T (OTDT) channel check surveillance required by technical specifications. The delta-T channel check being performed only included the OPDT and OTDT detectors, rather than the entire instrument loop.

* LER 423/94-02-00 documented that a shift turnover occurred without the minimum shift crew composition. The shift technical advisor was vacant for approximately 30 minutes.

* LER 423/94-03-01 documented that an outboard containment isolation valve was unlocked for approximately four hours. The valve was unlocked to verify that it was closed before red-tagging it closed to support maintenance.

* LER 423/94-05-00 reported the inoperability of the containment drain sump level and pumped capacity monitoring system to detect a one gallon per minute leak within one hour. This issue was previously reviewed in NRC Inspection Report 50-423/94-01.

* The noted LERs reported conditions prohibited by license requirements. The inspectors determined that the events were of minor safety significance and the criteria of section VII.B of the NRC Enforcement Policy were met. Therefore, enforcement discretion was exercised and no violation was cited.

6.2 Review of Previously Identified Issues

6.2.1 Operation of Cooling Water Systems Outside of Design Basis Temperature Limits - Unit 2 (URI 336/93-11-01)

On May 24, 1993, a main turbine trip followed by a reactor trip occurred at Unit 2 during restoration from thermal backwashing of a main condenser waterbox. The turbine trip was caused by high generator stator cooling system temperature. During a review of operational data following the event, the inspector identified that the service water (SW) and reactor building closed cooling water (RBCCW) systems had been operated briefly above the design limits (75 degrees Fahrenheit (°F) and 85°F, respectively) established in the Final Safety Analysis Report (FSAR). This unresolved item was opened pending NRC review of licensee corrective actions and actions to prevent recurrence.

Maximum SW and RBCCW heat exchanger outlet temperature limits are described in FSAR Sections 9.4 and 6.5, respectively. The RBCCW system temperature limit was further reinforced in a memorandum from the Unit 2 engineering department to the operations department dated January 4, 1993. The memorandum provided operational restrictions needed to support a plant operability determination regarding cooling water systems, which was performed pursuant to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The inspector noted that the RBCCW temperature restriction was added only to procedure OP-2326A, "Service Water," and that other affected procedures, such as OP-2330A, "Reactor Building Closed Cooling Water," OP-2325A, "Circulating Water," and OP-2301C, "Reactor Coolant Pump Operation," remained unchanged. In addition, the RBCCW system high temperature alarm on main control board CO6F and its alarm response procedure (OP form 2387E-140) remained set at 95°F, well above the 85°F design limit.

As corrective action, the licensee added the temperature limits to procedures and changed the RBCCW alarm setpoint to provide a warning prior to exceeding the design temperature. New procedure controls concerning thermal backwashing were established to monitor system temperatures and to terminate the evolution prior to exceeding design limits. The inspector verified that the changes were in place and concluded that these corrective actions were acceptable. As action to prevent recurrence, the licensee issued a memorandum, dated October 7, 1993, to the operations department procedure writers group emphasizing the need to perform a rigorous review of the entire procedure set when new plant operational requirements are identified. The inspector considered this action to be inadequate in that the SW and RBCCW system temperature limits were not new requirements in January 1993, and the root cause of the failure to incorporate design requirements into system operating procedures was not adequately identified or addressed. The inspector discussed this concern with the Unit Director on February 15, 1994. In response, a controlled routing was initiated directing the operations department to address the issue by April 5, 1994. Subsequent to that date, the inspector determined through review of the controlled routing that the required action had not yet been accomplished.

10 CFR 50, Appendix B, Criterion III, Design Control, requires measures to be established to assure that the design basis for safety-related systems is correctly translated into procedures. Licensee failure to ensure that the design maximum temperature limits of the SW and RBCCW systems were incorporated into operating procedures is a violation of this requirement. Although the procedural deficiencies were self-disclosing as a result of the unit trip event, the licensee's actions to prevent recurrence were not adequate to assure that other existing procedures were not similarly affected. Therefore, this **violation** will be cited (**VIO 336/94-17-10**). Item **URI 336/93-11-01** is **closed**.

6.2.2 Failure of Steam Generator Safety Valve To Reseat - Unit 3 (URI 423/93-07-05)

This item involved failure of a steam generator safety valve to re-seat following a reactor trip on April 3, 1993. The item was opened pending NRC review of the results of the licensee's event investigation and long term corrective actions. Examination of eleven safety valves overhauled by Crosby Valve and Gage Company revealed that the lower nozzle rings of seven valves had been misadjusted. Incorrect adjustment of the nozzle rings could cause the safety valves to re-seat significantly below lift pressure, resulting in excessive plant cooldown and potentially excessive radiological release to the environment during a steam generator tube rupture. The licensee found that contrary to the provisions of the QA purchase order, Crosby technicians had not adjusted the nozzle rings in accordance with the proper maintenance procedure.

In June 1993, the licensee performed a vendor services surveillance of Crosby which verified compliance with licensee quality program requirements. In addition, a comprehensive industry audit performed in August 1993 found Crosby's quality assurance program to be acceptable. Notwithstanding the above, the licensee discontinued sending the safety valves to

Crosby for refurbishment, and revised its QA vendor list to require a source inspection should the need to do so arise in the future. The inspector identified no licensee violations of NRC requirements and concluded that the licensee's corrective actions were acceptable. The vendor performance issues were forwarded to the NRC Vendor Inspection Branch. This item is **closed**.

6.2.3 Leaking Auxiliary Feed Pump Turbine Steam Isolation Valves - Unit 3 (URI 423/93-15-02)

This open item was initiated to review the licensee's corrective actions to repair and demonstrate satisfactory steam isolation performance of the auxiliary feedwater turbine steam isolation valves MSS*AOV31A, B, and D. The valves had a history of seat leakage which resulted in the steam turbine maintaining a slow spin with the governor in the stop position. Subsequent starting of the TDAFW pump in this condition led to a pump trip on overspeed and the consequent temporary unavailability of the TDAFW pump. The subject valves were overhauled during the cycle four refueling outage. The repair consisted of machining and weld repair (with inconel) of the valve body to improve the body to valve cage seating surface, which had been pitted. The inspector verified that the valve leakage was returned to within the design specification, and that there have been no subsequent instances of the turbine rolling from steam leakage past these valves. The inspector considered the licensee's corrective actions to be acceptable. This item is **closed**.

6.2.4 Bypass Jumper Controls (VIO 423/92-28-06) - Unit 3

This item involved a violation of technical specification administrative requirements for the control of temporary plant modifications. Specifically, during a review of bypass jumper controls at Unit 3, the inspector found 22 instances, six involving scaffolding installations, in which procedural due dates for review by the plant operations review committee (PORC) were exceeded. The violation was documented in NRC Inspection Report 50-423/92-28, dated February 1, 1993. In their response to the Notice of Violation dated March 8, 1993, the licensee attributed the failure to conduct the PORC reviews to management inattention to administrative requirements, and stated that procedure changes would be made to facilitate tracking of long-term installations, and that Unit 3 would be in full compliance with resolution to long-term bypass jumpers by May 1, 1993.

On April 5, 1994, the inspector performed a review of jumper bypass controls at Unit 3 to assess the adequacy of the licensee's corrective actions. Administrative control procedure ACP-QA-2.06B, "Jumper, Lifted Lead, and Bypass Control," step 1.6.10, requires the PORC to review all jumper devices installed for greater than three months. However, the inspector identified several scaffolding bypass jumpers which had been in effect for longer than three months, and which had not been reviewed by the PORC. For example, jumper number 3-93-058 for a scaffold erected in the ESF Building had been identified for six successive months by the operations shift supervisor as requiring PORC review with no action being taken. The inspector discussed the finding with the licensee, who initiated a

plant information report to evaluate and correct this matter. Subsequently, the licensee determined that nine scaffolding bypass jumpers had not been reviewed by the PORC after the three month installation limit had been exceeded. The licensee performed a root cause barrier analysis and identified the cause as confusion over assigned responsibilities, and lack of ownership and accountability for the jumpers. To address the root cause, the licensee assigned the unit administrative staff the responsibility for updating the bypass jumper tracking system and providing reports to department managers. The PORC secretary will be provided the list of bypass jumpers requiring PORC review on a monthly basis. In addition, scaffolding will be controlled under a new program with clearly defined responsibility for tracking. The inspector concluded that the root cause had been plausibly addressed by these corrective actions.

10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires measures to be established to assure that the cause of significant conditions adverse to quality is determined and that corrective actions are taken to preclude repetition. The inspector concluded that the actions to prevent recurrence outlined in the licensee's violation response dated March 8, 1992, were not implemented effectively by Unit 3 management. Therefore, the subsequent violations of procedure ACP-QA-2.06B were not prevented. This is a second example of inadequate corrective action, and will be cited in conjunction with the **violation** detailed in Section 3.4 of this report. **(VIO 423/94-16-05)** Item **VIO 423/92-28-06** is **closed**.

7.0 MANAGEMENT MEETINGS

Periodic meetings were held with various managers to discuss the inspection findings during the inspection period. Following the inspection, exit meetings were held on July 13 and August 5, 1994, to discuss the inspection findings and observations with station management. Licensee comments concerning the issues in this report were documented in the applicable report section. No proprietary information was covered within the scope of the inspection. No written material regarding the inspection findings was given to the licensee during the inspection.

ATTACHMENT 1

Millstone Unit 1 Plant Design Change Records Reviewed

1-07-93	Dual Setpoint Low Pressure Coolant Injection System Drywell Pressure Switches and Automatic Isolation of Reactor Building Closed Cooling Water to the Drywell
1-61-93	Isolation of Containment Purge and Vent Valves
1-79-93	'B' Emergency Service Water Stainer Replacement
1-78-93	Replacement of Low Pressure Coolant Injection Check Valves
1-65-93	Removal of Valve 1-LPC-28A
1-86-93	Service Water and Emergency Service Water Modifications (PA 92-078)
1-74-93	Increase Emergency Diesel Generator Overspeed Setpoint
1-123-92	Change Core Spray Injection Valve Control Logic
1-99-92	Add Emergency Diesel Generator Room Temperature Indication/Alarm
1-87-93	14-CSS-4A Weldolet Installation
1-70-93	Add Check Valves to Emergency Diesel Generator Keep-warm Supply and Return Lines
1-58-93	Emergency Service Water/Service Water Strainer Differential Pressure Switch Replacement
1-92-93	Standby Liquid Control Pump Trip Annunciation
1-67-93	Indication for the Gas Turbine Starting Air Overspeed Switch Reset
1-25-93	Control Room Design Review Phase II