U.S. NUCLEAR REGULATORY
REGION I

Report No. 50-423/89-08

Docket No. 50-423

License No. NPF-49

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

Facility Name: Millstone Nuclear Power Station, Unit 3

Inspection At: Waterford, Connecticut

Inspection Conducted: May 15 to June 12, 1989

Reporting Inspector: W. J. Raymond, Senior Resident Inspector

Inspectors: W. Raymond, Senior Resident Inspector
F. Crescenzo, Senior Resident Inspector, Shoreham
D. Jaffee, Project Manager, NRR
G. Garten, Project Engineer, NRR
A. Asars, Resident Inspector, Haddam Neck
A. Krasopoulos, Reactor Engineer
S. Barr, Reactor Engineer

Approved by: Elm C. McCabe, Jr. 7/11/89
E. C. McCabe, Chief, Reactor Projects Section 1B Date

Inspection Summary: Inspection on 5/15/89 - 6/12/89

Areas Inspected: Routine onsite inspection (232 hours) of plant operations, Unresolved Item (50-423/87-12-01), previous inspection findings, Plant Incident Reports, Incore Thimble degradation, safety evaluations performed per 10 CFR 50.59, licensee actions in response to Generic Letter 88-17, procedures for reduced inventory and other actions for Generic Letter 88-17, design change training for operators, modifications reviews, refueling operations, maintenance, surveillance, and Licensee Event Reports.

Results: No violations or unsafe conditions were identified. Licensee and NRC follow-up of tagging operations is warranted to assure the correct control of safety-related systems (see Section 5.2). Licensee actions in response to Generic Letter 88-17 and preparations for operation with reduced RCS inventory were acceptable (see Sections 8.0 and 9.0).

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DETAILS

1.0 Persons Contacted

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

S. Scace, Station Superintendent
C. Clement, Unit Superintendent, Unit 3
M. Gentry, Operations Supervisor
R. Rothgeb, Maintenance Supervisor
K. Burton, Staff Assistant to Unit Superintendent
J. Harris, Engineering Supervisor
D. McDaniel, Reactor Engineer
R. Satchatello, Health Physics Supervisor
M. Pearson, Operations Assistant
H. Covin, Operations Assistant
R. Enoch, I&C Supervisor

2.0 Summary of Facility Activities

The plant was in cold shutdown at the start of the inspection period and in day 6 of a scheduled 52 day refueling and maintenance outage.

Major activities for Refueling Outage #2 included installation of reactor level instrumentation for mid-loop operation, installation of an ATWS mitigation system, ISI weld inspections, steam generator tube eddy current testing, vessel refueling and inspection of core components, vessel examinations, and service water system inspections and repairs.

The plant remained shutdown for the refueling outage at the end of the inspection period, with fuel shuffle activities complete and testing of the 'A' train engineered safety features components in progress.

3.0 Status of Previous Inspection Findings

3.1 (Closed) Unresolved Item (50-423/87-12-01), Inadvertent Actuation of the Carbon Dioxide System During Testing

The licensee, while performing a surveillance of the fire detection system in the East MCC/RCA area, accidentally caused a Carbon Dioxide system actuation and discharge. The cause of this event was an inadequate procedure and lack of adequate training of the operators performing the surveillance.

The licensee addressed these problems as follows:

(1) The detection system surveillance procedure, SP3641D.3, was revised to include the precaution that gaseous suppression systems (Carbon Dioxide and Halon) must be isolated prior to performing any tests on systems that could activate the Carbon Dioxide or Halon system.

(2) Operators and other plant personnel are being given additional training to increase awareness of gaseous fire suppression system hazards.

(3) The licensee has implemented a new procedure, OP3341E, controlling access and work in areas protected by a Carbon Dioxide suppression system. This procedure also requires Carbon Dioxide system isolation when work is being performed in these areas.

The above activities address the NRC concerns in this area and resolve this item.

4.0 Review of Facility Activities (71707)

The inspector reviewed plant operations from the control room and reviewed the operational status of plant safety systems to verify safe operation of the plant in accordance with the requirements of the technical specifications and plant operating procedures. This review included periodic verification that Technical Specification 3.4.1.4.2 and 3.4.9.3 requirements for reactor shutdown cooling and vessel overpressure protection were met.

Plant logs and control room indicators were reviewed to identify changes in plant operational status since the last review and to verify that changes in the status of plant equipment was properly communicated in the logs and records. Control room instruments were observed for correlation between channels, proper functioning and conformance with technical specifications.

Alarm conditions in effect were reviewed with control room operators to verify proper response to off-normal conditions and to verify operators were knowledgeable of plant status. Operators were found to be cognizant of control room indications and plant status. Control room manning and shift staffing were reviewed and compared to technical specification requirements.

No inadequacies were identified.

4.1 Service Water System Leakage

The Millstone Unit 3 Service Water System (SWS) supplies salt water cooling to various safety and non-safety related components. The service water system supplies filtered water for lubrication of the

circulation and service water pump bearings and also serves as a backup source of water (emergency) for the spent fuel pool, for auxiliary feedwater, and for control building chilled water makeup.

Since 1987, the Service Water System has experienced minor chronic leakage. The licensee described his program for addressing service water system leakage in a letter to the NRC dated April 28, 1989. Previous NRC review of this area is described in Inspection Report 89-04.

During this inspection, the Production Maintenance Management System (PMMS) was queried as to the number of Automated Work Orders (AWOs) that were issued to repair Service Water leakage. The PMMS printouts indicated that one AWO was issued in 1987, a total of 17 AWOs were issued in 1988 and, as of June 1, 1989, 10 AWOs had been issued.

During the outage, the Service Water System was inspected and the licensee's repair program was discussed with licensee personnel. The following observations were made:

-- Many of the Service Water leaks have occurred in small/medium bore Copper/Nickel pipe. The leaks seem to occur near pipe "Ts", elbows or reducers. The licensee has, where possible, replaced elbows with wide radius sweeps to decrease erosion. The licensee has also replaced some Copper/Nickel pipe fittings with Monel fittings which the licensee expects will increase corrosion resistance.

-- A few Service Water leaks have occurred in large bore pipe, including leaks at the SWS outlet from the "A" Reactor Plant Component Cooling Water Heat Exchanger, and from the SWS supply to the turbine plant heat loads.

-- At least one Service Water System leak was caused by poor material selection. The large bore pipe between the "B" Diesel Generator Intercooler and Jacket Cooler developed a leak and was subsequently identified as unlined carbon steel. This material is unsuitable for salt water service. During the present refueling outage, the subject pipe and the corresponding pipe at the "A" Diesel Generator will be replaced with lined stainless steel pipe.

-- Licensee actions completed during the outage included the completion of repairs to the service water leaks on large bore piping in the vicinity of valves V35, V71A and V71B. The inspector reviewed work activities in progress to weld repair the piping wall defects and to apply Balzona as a corrosion protection layer.

The inspector noted, by visual inspection of the pipe sections with the through-wall defects, that the corrosion was highly localized in the affected areas. No inadequacies were identified in the repair efforts.

The inspector had no further questions regarding the salt water corrosion/erosion problem associated with the Service Water System at the present time. Inspection item 50-423/89-04-01 tracks additional NRC follow-up of this issue. Licensee actions in this area will be reviewed further on subsequent routine inspections.

4.2 Charging Pump/Lube Oil Pump Coupling

Westinghouse Technical Bulletin NSID-TB-85-19, dated September 24, 1985, addresses a wear problem in the coupling between the charging pump speed increaser and the associated lube oil pump. Failure of this coupling occurred at D.C. Cook Unit 1 and Almaraz Unit 1. Westinghouse recommends that the coupling be inspected during each refueling outage.

The inspector was present when the "B" charging pump (3CHS*P3B) was undergoing maintenance during the refueling outage. When the subject coupling was removed for inspection, wear was clearly visible on both pins and both holes. The design pin diameter is 0.50 inches and minimum pin diameter was 0.47 inches on each pin. The design hole diameter is 0.56 inches and the maximum hole diameter was 0.60 inches on each hole. The acceptance criteria in NSID-TB-85-19 are a minimum pin diameter of 0.375 inches and a maximum hole diameter of 0.750 inches.

Based upon the Westinghouse acceptance criteria and consultation with Westinghouse, the licensee feels that the coupling will be acceptable for a number of refueling cycles and should be reinstalled "as is." Replacement parts will be obtained as a precaution. The licensee's Nonconformance Report 389-127 documents the acceptance of the coupling wear.

No inadequacies were identified in the licensee's evaluations or corrective actions.

5.0 Plant Operational Status Reviews (71707)

5.1 Review of Plant Incident Reports

The plant incident reports (PIRs) listed below were reviewed to (i) determine the significance of the events; (ii) review the licensee's evaluation of the events; (iii) verify the licensee's response and corrective actions were proper; and (iv) verify that the licensee reported the events in accordance with applicable requirements, if required. The PIRs reviewed were: 76-89, 63-89, 62-89 and 73-89.

PIR 73-89 regarding setpoint drift problems with 14 of 20 main steam safety valves warranted inspection followup and is discussed further in Section 13.2 of this report.

5.2 Tag-out Error During "B" Diesel Generator Maintenance

During inspection of "B" Diesel Generator maintenance, the associated Tag-out, 3-3880-89, was checked for correct implementation. Two items, Tag 26 (Jacket Water Circulation Pump Switch - 3EGS*P2B) and Tag 28 (Generator Space Heater Switch - 3EGS*H2B) were incorrectly set. The tag log sheet for 3-3880-89 shows 3EGS*P2B and 3EGS*H2B in the "off" position (both switches were found to be in the "on" position). The circuit breakers for 3EGS*P2B and 3EGS*H2B were verified to be in the correct "off" position.

The licensee promptly restored 3EGS*P2B and 3EGS*H2B to their correct "off" position and generated PIR 76-89. Licensee review of the cause of the subject switch misalignment problem will be completed as part of the PIR evaluation and will be reviewed on a subsequent routine NRC inspection.

The inspector noted that the safety significance of the tagging error was minimal since personnel and equipment protection was provided by the upstream breakers. Further, the inspector noted that this may be an isolated example of a problem with correct performance of tagging operations at Millstone 3. This item is unresolved pending NRC review of the licensee's PIR evaluation and pending further inspection of tagging (UNR 89-08-01).

6.0 Incore Thimble Degradation (71707)

The licensee performed eddy current testing (ECT) during the refueling outage on the incore instrumentation thimbles to determine the degradation of the thimble tube wall thickness. The ECT was performed as a result of Information Notice 87-44 and as a follow-up to ECT performed in the first refueling outage (see Inspection Report 87-33). The results of the first ECT were reviewed by Westinghouse, where it was subsequently recommended that thimbles with a wall thickness diminished by greater than 50% should be either repositioned or capped off. In addition, Westinghouse concluded that thimble tubes with 60% material wear loss over a length of 1/2 inch are structurally adequate to withstand RCS pressures. During the last outage, six thimbles were determined to have a wall loss in excess of 25% and were subsequently retracted 1.25 inches. One thimble (cube no. 41-N-4) was found to have a wall loss of approximately 38% and was capped off and left in place for future degradation measurements. The remaining thimble tubes had either no wall loss or had wall loss of less than 25% and no corrective actions were taken.

Of the six thimble tubes that were previously retracted, one (tube no. 45-P-4) displayed wall loss in the newly exposed area. This tube will be retracted an additional 1.25 inches. It had initially been thought that the maximum amount that any thimble tube could be withdrawn was 2 inches. However, subsequent review has shown that a thimble tube can be retracted by as much as 4 inches. The licensee has determined that the additional axial retraction will have no adverse impact on incore flux readings. In addition, a second thimble tube, one not previously retracted, will also be retracted 1.25 inches. The thimble that had previously been capped off has shown an additional wall loss of approximately 5%. This subsequent degradation will be noted for future reference in an effort to develop a curve displaying wall thickness degradation rates. Another thimble, tube no. 45-N-13, showed approximately 58% wall loss and will also be capped off. The licensee is obtaining additional information on whether or not areas that had been previously retracted (not exposed during last cycle) have shown any new wall loss.

The licensee's approach to monitoring, capping and retracting tubes was found consistent with recommendations from Westinghouse and similar repairs at other plants as noted in Information Notice 87-44. Furthermore, the licensee is considering a Westinghouse magnetic isolation valve as a means by which a leaking thimble can automatically be isolated. Follow-up ECT is to be performed during the next outage to identify the need for additional corrective action and possible long-term solutions to the wall loss problem.

No inadequacies were identified. The inspector had no further questions.

7.0 Audit of Safety Evaluations Performed per 10 CFR 50.59 for 1988 (37700)

The licensee's procedure ACP QA-3.26, "PDCR Evaluation," requires that changes to the facility be evaluated for safety significance. Those changes which could impact plant safety are designated with a plant design change records (PDCR) number and evaluated per NEO 3.03, "Preparation, Review, and Disposition of Plant Design Change Records." The requirements of NEO 3.03 include the need for a safety evaluation.

Table 1 (at the end of this report) lists PDCRs selected from the PDCRs in the licensee's 1988 Annual Report. These PDCRs were selected for review since they involve "safety-related" systems. Each PDCR reviewed contained a safety evaluation (Safety Evaluation and/or Safety Evaluation Worksheet and/or Integrated Safety Evaluation in accordance with NEO 3.12, "Safety Evaluation.") For each of the PDCRs in Table 1, the safety evaluation was reviewed and found to meet the safety evaluation requirements of 10 CFR 50.59 (b)(1) in that the PDCRs "...include a written safety evaluation which provides the bases for the determination that the change, test, or experiment does not involve an unreviewed safety question."

For plant changes which are judged to be minor, the change can be implemented within the controls specified by ACP QA-3.26. The safety evaluation requirements of QA-3.26 allow either a written safety evaluation per NEO 3.12 or certification that no safety evaluation is required. Two plant design change record evaluations (PDCEs) reported in the 1988 Annual Report were evaluated regarding 10 CFR 50.59, as shown in Table 1. Both of these PDCEs (MP3-88-022 and MP-3-88-059) involve systems described in the FSAR (Auxiliary Feedwater Pumps and Reactor Coolant Pumps, respectively) but neither of these PDCEs contains a written safety evaluation. This situation was judged to be acceptable in that the changes did not affect the safety function of the subject component/system and thus did not represent changes to the facility as described in the FSAR.

Table 2, also at the end of this report, is a summary of other activities, reported in the 1988 Annual Report, which are subject to the licensee's 10 CFR 50.59 review process. In those cases where a safety evaluation was prepared, the safety evaluation was found to be adequate to meet 10 CFR 50.59 (b)(1). In the case of 3-87-023 and 3-87-014, no safety evaluations were provided. This situation was judged to be acceptable in that the subject procedural changes did not change the safety function of any component or system credited in the FSAR.

The descriptive and safety evaluation material in the 1988 Annual Report was reviewed for those activities listed in Tables 1 and 2. It was concluded that material required to be submitted in the Annual Report per 10 CFR 50.59(b)(2) meets the requirements of the rule with regard to the description of the activities and a summary of the associated safety evaluations.

Based upon the above, the licensee met the requirements of 10 CFR 50.59. Areas that were acceptable included maintenance of records for facility changes, procedure changes, and tests including safety evaluations as appropriate, and reporting of these activities. No inadequacies were identified.

8.0 Review of Licensee Actions in Response to Generic Letter 88-17, Loss of Decay Heat Removal (TI 2515/101)

Loss of decay heat removal during nonpower operation and the accompanying consequences have received increased attention in the nuclear industry during the last several years. Recent events at nuclear plants have increased the awareness of and insight into these events. In response, NRC issued Generic Letter (GL) 88-17, Loss of Decay Heat Removal, on October 17, 1988.

The GL identifies deficiencies in procedures, equipment, and training in the areas of accident prevention, accident mitigation and the control of radioactive materials in the event of core damage following a loss of decay heat removal capability. Accordingly, licensees were asked to implement expeditious actions and program enhancements to improve procedures,

equipment, and training in this area. The expeditious actions were to be completed prior to entering reduced inventory operations. The program enhancements are to be completed prior to startup from the second refueling outage after issuance of the GL.

The licensee responded to this GL by letters dated December 23, 1988 and January 31, 1989. These letters described the actions to be taken in accordance with GL 88-17. The inspector reviewed these responses and conducted an inspection of the implementation of the expeditious actions. The program enhancements will be reviewed during a future inspection.

During February 1989, the licensee experienced an unplanned shutdown for repair of a hot leg loop stop valve leak. This repair required mid-loop operation. Special procedures were prepared and operator training was conducted prior to mid-loop operation. The repair effort and mid-loop operation are described in NRC Inspection Report 50-423/89-02.

The licensee will operate with reduced inventory and at mid-loop during the current refueling outage. Operation in this condition is required for Inservice Inspection of eight pressure isolation check valves in the Low Pressure Safety Injection and Safety Injection Accumulator discharge flow paths and to perform maintenance on the eight loop stop valves.

8.1 Redefinition of Reduced Inventory

The expeditious actions identified by the GL are to be implemented prior to entering into reduced inventory operations. Reduced inventory operations occur whenever the reactor vessel water level is more than three feet below the reactor vessel flange.

Millstone Unit 3 has elected to redefine the minimum reactor vessel level for reduced inventory operations from three feet to five feet below the reactor vessel flange. This is because of the inverted "top hat" design of the reactor upper internals package. The upper internals sit lower in the reactor vessel than in the standard design considered by the GL. The redefinition of reduced inventory will prevent overflow and possible introduction of debris and contaminants into the reactor vessel flange and stud holes when the upper internals are placed in the vessel.

The licensee elected to use two methods for determination of the minimum height at which air entrainment into the RHR (Residual Heat Removal) system can be avoided: the Harleman Equation and a scale model test.

The Harleman Equation calculates the minimum reactor water level as a function of RHR flow velocity and system dimensions. The licensee determined, based on this calculation, that a minimum water level of 19' 6" with the normal RHR flow of 4000 gpm would be sufficient to avoid air entrainment.

A scale model test of the Millstone 3 Reactor Coolant System (RCS) during mid-loop operation was conducted by Westinghouse Electric Co. The experiment concluded that a water level of at least 17' 6" is necessary to avoid RHR air entrainment.

The licensee elected to use the more conservative level (19' 6") as the redefined reduced inventory level. This is equivalent to five feet below the reactor vessel flange.

The inspector reviewed the calculation assumptions and results and the model test results. No discrepancies were identified. Additionally, the acceptability of redefinition of reduced inventory was discussed with the technical contact for this Generic Letter in NRC Headquarters. The inspector was informed that this is acceptable and that other sites with reactor upper internals designs similar to Millstone 3 were also redefining reduced inventory levels.

No inadequacies were identified. The inspector had no further questions regarding the definition of reduced inventory operations as it related to the GL guidance. NRC review of other licensee actions in response to GL 88-17 are discussed further below.

9.0 Review of Procedures for Reduced Inventory Operation and Other Actions for Generic Letter 88-17 (TI 2515/101)

The following three procedures are in effect for draining the RCS, operating with the reduced inventory, and recovering from a loss of shutdown cooling. The inspector reviewed the revisions in effect and discussed with the licensee several inadequacies and areas for improvement. At the close of the inspection period, the licensee was evaluating changes to improve the procedures. The inspector noted that these procedures were used without incident during the mid-loop operations in February, 1989.

9.1 OP 3270, Reduced Reactor Coolant System Inventory Operation

This procedure was initially written to support mid-loop operations for February, 1989. Its objective is to provide guidance and direction for RCS operation at reduced inventory and mid-loop levels.

The inspector reviewed Revision 1 which was scheduled for Plant Operation Review Committee (PORC) review during the inspection. The following areas for improvement were noted:

-- Minimum RCS venting requirements to prevent pressurization were not specified.

-- Reference points for vessel water level varied, potentially creating confusion.

-- RHR flow limits were not specified for operation when in reduced inventory conditions.

-- There was no prerequisite for operable gravity flow paths from the Refueling Water Storage Tank (RWST).

-- There was no prerequisite that RWST level be greater than 90% of the Technical Specification requirement for mode 1,2 and 3 in accordance with the assumptions of the calculations to support gravity feed of the RWST to the vessel.

-- There was no prerequisite specifying the condition of the unisolated steam generators, specifically, full and indicating on the narrow range level instrumentation.

These items were discussed with Operations and Engineering personnel and at the close of the inspection were under licensee review for incorporation into the procedure.

9.2 OP 3301E, Draining the Reactor Coolant System Drain

OP 3310E provides for draining of the RCS and maintaining RCS level below seven percent in the pressurizer. The inspector reviewed Revision 2, effective April 20, 1989, and noted the following:

-- The precaution statement requiring a seven square inch vent path is not consistent with the 20.43 square inch vent path assumed by the calculations to support gravity feed from the RWST.

-- Figure 10.2, Duties and Responsibilities of Reactor Vessel Level Watch, is not consistent with current operational practices and commitments.

These items are also under licensee review.

9.3 EOP 3505, Loss of Shutdown Cooling

EOP 3505 is an Abnormal Operating Procedure newly written in the Westinghouse Emergency Response Guideline format. Each step has an action/expected response and response not obtained column.

Concurrent with the inspection, during procedure review for lesson plan preparation, Operator Training personnel identified discrepancies which were being incorporated as a revision to the procedure.

The inspector questioned whether Revision 2 to EOP 3505 had been validated on the simulator or through walkdown. Since this procedure is an Abnormal Operating Procedure versus an Emergency Operating

Procedure, the validation process can be waived as it was in this example. Nonetheless, had this procedure been validated, it is likely that the deficiencies would have been identified earlier.

9.4 Plant Design Change Record MP3-89-008

PDCR (Plant Design Change Record) MP3-89-008, Control Room Shutdown Level Indication and RHR Performance Monitoring, was initiated during this refueling outage. The modification alters the monitoring of RCS level, RCS temperature, and RHR performance during cold shutdown and mid-loop operation in the following four ways.

1. Video monitoring is to be installed to monitor tygon tube vessel level indication directly from the control room.

2. Three level transmitters installed in the RHR pump suction and RCS letdown lines continuously monitor RCS level from the vessel flange to the bottom of the hot leg.

3. Operating procedures were modified to ensure that the vessel head is in place, the RVLIS (Reactor Vessel Level Indication System) probes are in operation, and at least two Core Exit Thermocouples (CETs) are operational prior to entering reduced inventory conditions.

4. An RHR Performance Monitoring software package, using new level transmitters and already existing instrumentation, was installed in the Millstone 3 process computer to monitor and trend RHR performance.

The video monitoring in the control room will not be installed during this outage. In the interim, a locally stationed vessel level watch will be in constant communication with the control room and record vessel level every fifteen minutes.

The inspector reviewed the PDCR package and observed portions of the level transmitter installation. The operating procedure changes were also reviewed to verify that necessary changes were incorporated. Additionally, the inspector reviewed the draft post-modification test for the level transmitters and the performance software package, IST 3-89-005, Reactor Coolant System Level Monitoring. No deficiencies were identified.

9.5 Training

GL 88-17 specifies that training be provided to the appropriate plant personnel, including discussion of the Diablo Canyon event, related events, lessons learned, and the implications of these events. The training is to be provided shortly before entering a reduced inventory condition.

The inspector met with Operator Training personnel and reviewed the lesson plan for the training which was conducted in February, 1989 prior to mid-loop operations. The training was conducted on a pre-shift basis for all licensed on-shift operators and all plant equipment operators. The agenda included a review of the mid-loop operation procedures, operation of the RHR system, and the Diablo Canyon event. The discussion also included emphasis on ways in which the RCS can be perturbed and symptoms of air entrainment in the RHR system.

On May 24, the inspector attended the first of the training sessions to be conducted prior to entering mid-loop conditions during this outage. The discussion of mid-loop operation lasted approximately 30 minutes. PDCR MP3-89-008 was described as well as the applicable operating procedures and highlights of the Diablo Canyon event.

During this session, operators identified an apparent conflict between OP 3208, Plant Cooldown, Revision 3, and OP 3270. Procedure Change 4 was issued to OP 3208 on February 23, 1989 to mitigate an overpressure incident due to a safety injection while the RCS is solid. This change requires that the charging pump discharge motor-operated valves be closed, red tagged, and the breakers be racked out whenever that RCS temperature is less than 200 degrees F. This is in conflict with OP 3270 which requires operable flow paths from the RWST for a gravity feed to the RCS in the event the RHR pumps are inoperable. The licensee is evaluating methods to resolve this conflict.

The inspector also discussed mid-loop operations training for Health Physics, Maintenance, and Instrumentation and Control Personnel.

Health Physics personnel receive radiological system training on a two year cycle. This training includes detailed review of the RHR system and the Diablo Canyon event. The Millstone 3 training on loss of RHR was conducted during the first several months of 1989.

Maintenance and Instrumentation and Controls personnel received training on the sensitivities associated with mid-loop operations during department meetings in March and May, respectively. The agendas included discussion of GL 88-17, previous loss of RHR events, and prevention and consequences of RCS perturbations during mid-loop operations.

No deficiencies were identified in these training programs.

9.6 Containment Closure

Containment closure is defined by GL 88-17 as a containment condition where at least one integral barrier to the release of radioactive materials is provided. Containment closure must be achieved prior to the time at which a core uncovery could result from a loss of RHR coupled with an inability to initiate alternate cooling or addition of water to the RCS.

The licensee has committed to maintain containment closure during reduced inventory operations with one exception. A containment barrier may be open during reduced inventory with prior approval by PORC. These barriers must be closed prior to projected core uncovery and are controlled by OP 3270. Additionally, the licensee has evaluated the equipment hatch closure requirements and provided guidance for the number of bolts, bolting pattern, and bolt tension.

9.7 Reactor Coolant System Temperature

GL 88-17 specifies at least two independent continuous temperature indications that are representative of the core exit conditions whenever the RCS is in a mid-loop condition and the reactor vessel head is in place. Temperature indications are to be periodically checked and recorded or automatically and continuously monitored and alarmed. Temperature monitoring should be performed by an operator in the control room or from a location outside of the containment building with provision for providing immediate temperature values to the control room should any significant changes occur.

The licensee has committed to maintaining two operable CETs with the ability to monitor RCS temperature on the plant process computer. This monitoring capability is being incorporated into the RHR Performance Monitoring software package.

The inspector verified that the CETs are required to be operable per OP 3270, in accordance with the GL. It was also noted that the RHR Performance monitoring software package did not provide an alarm for high temperature indication by the CETs. However, OP 3270 will include a periodic log of temperature when the RCS is in a reduced inventory condition.

9.8 Reactor Coolant System Water Level

At least two independent, continuous RCS water level indications are specified whenever the RCS is in a reduced inventory condition. Water level should be periodically checked and recorded or continuously monitored and alarmed. Water level should be monitored by an operator in the control room or from a location with provision for

providing immediate water level values to the control room should significant changes occur. Observations should be recorded at intervals no greater than fifteen minutes.

Millstone 3 installed three independent RCS water level transmitters in the RHR pump suction and RCS letdown lines by PDCR MP3-89-008. This PDCR is discussed in Detail 9.3 of this report. Additionally, the RVLIS system will be operational and monitored by the plant process computer.

The inspector reviewed the PDCR and associated procedural controls. It was noted that the RHR performance software package also does not provide for an alarm for the RVLIS indication. However, provisions for a periodic log of water level while the RCS is a reduced inventory condition are contained in OP 3270.

9.9 Reactor Coolant System Perturbations

GL 88-17 requires that procedures and administrative controls be implemented that generally avoid operations that deliberately lead to perturbations to the RCS and other systems needed to maintain the RCS in a stable and controlled condition while the RCS is in reduced inventory conditions.

OP 3270 and 3301E provide for the control of plant systems and configurations while in a reduced inventory condition. These procedures are discussed in Detail 9.2 of this report. Additionally, the possibility and consequences of RCS perturbations were discussed in the pre-mid-loop training for the Millstone 3 staff.

9.10 Alternate Sources of Reactor Coolant System Inventory

At least two available or operable means of adding inventory to the RCS, in addition to pumps that are part of the normal RHR systems, are specified. These should include at least one high pressure injection pump. The water addition rate capable of being provided by each of these means should be at least sufficient to keep the core covered. Procedures should be provided for these water sources.

The licensee has provided for forced flow paths from the RWST through the charging, safety injection, and recirculation spray pumps. Additionally, a path for gravity feed from the RWST through the charging and safety injection systems is to be operable.

The inspector reviewed the proposed flow paths and calculations to support the gravity feed from the RWST with Operations, Site Engineering, and Corporate Engineering personnel. The gravity feed calculation assumes that a vent path exists which is equivalent to one pressurizer safety valve removed (20.43 square inches). The inspector noted that provisions for an adequate vent path, to ensure that

the proposed forced and gravity feed flow paths are operable, and that the RWST contained the inventory assumed for the gravity feed calculations were not contained in the associated operating procedures. These were discussed with the licensee and are to be evaluated for incorporation in the procedure revisions.

9.11 Control of Reactor Coolant System Loop Stop Valves

Administrative procedures and controls shall be implemented to assure that all RCS hot legs are not blocked simultaneously by closed loop stop valves unless a vent path large enough to prevent pressurization is provided or unless the RCS configuration prevents water loss if pressurization should occur.

OP 3270 requires that at least one RCS loop be operable when in reduced inventory conditions and no more than two RCS loop will be isolated at one time. Additionally, it was noted that Millstone 3 has loop stop valve interlocks which prevent opening of the cold leg loop stop valves unless the hot leg loop stop in the same loop is open.

The inspector verified that OP 3270 did include these provisions. No deficiencies were identified.

9.12 Conclusion

The inspector concluded that Millstone 3 has adequately met the required expeditious actions of GL 88-17. Items were noted by the inspector for evaluation and possible incorporation in the operations procedures to strengthen the procedures and controls for operation under reduced inventory conditions.

10.0 Design Change Training for Operators

On May 24, the inspector attended the first session of outage modification training for licensed and non-licensed operators. The training is being conducted for operators following shift turnovers and lasts approximately one hour. The agenda included changes to Technical Specifications (TSs), plant modifications, and a discussion of operations with reduced inventory conditions as required by NRC Generic Letter 88-17.

The session included detailed discussions of the modifications and associated operational implications and procedure changes. Operators were inquisitive and made comments on apparent conflicts between new procedures and existing procedures. A handout had been prepared which describes in detail each modification and associated TS and procedure changes.

The inspector found the training to be adequate and identified no concerns.

11.0 Modifications Reviews (37828, 37700)

Plant modifications performed to meet regulatory commitments were selected for review as discussed below. Modifications performed in response to generic letter 88-17 were also reviewed as discussed in Section 9.4 above.

11.1 Annunciator Reduction Modification (Blackboard)

The inspector reviewed Plant Design Change Record (PDCR) MP3-88-013 Revision 1, which reduces the number of unnecessarily lighted annunciator windows in the main control room. This represents "phase II" of a program implemented to comply with a commitment to achieve a "blackboard" on the main control board.

The procedure provides instructions to revise logic schemes such that annunciator windows will not be illuminated when the associated systems are not in service. Three annunciators were modified:

-- Auxiliary Feedwater Pump "A" Lube Oil Pressure Low.

-- Auxiliary Feedwater Pump "B" Lube Oil Pressure Low.

-- Turbine Plant Component Cooling Water Heat Exchanger Service Water Outlet Pressure Low.

The auxiliary feedwater (AFW) lube oil pumps are shaft driven off the main AFW pump. Currently, the AFW low lube oil annunciators are needlessly illuminated whenever the main AFW pumps are not operating. The modification will interlock the annunciators with AFW pump switchgear such that the annunciator will illuminate only when the pump is operating and the alarm condition exists (low lube oil pressure).

The Turbine Plant Component Cooling Water (TPCCW) heat exchanger service water low pressure annunciator illuminates whenever a low service water pressure condition exists in one of the three TPCCW heat exchanger. The TPCCW heat exchangers are each designed to handle 50% rated load. Under normal conditions, one of the three will be out of service causing the alarm condition. The modification will interlock the annunciator with the discharge valve on each heat exchanger. When the valve is closed, the annunciator logic associated with that heat exchanger will be disabled.

The inspector reviewed the PDCR package for compliance with Station Procedure ACP-QA-3.10, Preparation, Review and Disposition of Plant Design Change Records. The inspector reviewed the technical adequacy of the PDCR as well as the adequacy of the 10 CFR 50.59 Safety Assessment. The inspector noted that Plant Operations Review Committee (PORC) approval for implementation had not yet been obtained.

Several other minor administrative items were also missing. The inspector verified, through discussion with the cognizant plant engineer, that this was consistent with ACP-QA-3.10. All required approvals, including PORC, could be deferred until the package was released to the field. Minor "Pre-construction" items had been released for work. These were properly approved and released. The technical aspects and safety evaluation were found to be adequate. The inspector had no further questions.

11.2 Electrical Protection Relay Modifications "Generator Coastdown"

The inspector reviewed PDCR MP3-89-010 to accomplish modifications to electrical protection relaying schemes that were required (in part) to correct a design deficiency described in LER 88-26. Four separate modifications were included in the package. These were:

-- Revision of the fast transfer scheme on the 4KV buses to block a sustained undervoltage condition on the 4KV bus from initiating a fast transfer from the Normal Station Service Transformer (NSST) to the Reserve Station Service Transformer (RSST).

For the 4KV system, the opening of the NSST supply breaker (other than control switch operation) will initiate a transfer to the RSST. The fast transfer time is short enough (several cycles) to ensure that decaying residual voltage on the 4KV bus, and RSST voltage, are not out of synchronization (sync). A fast transfer is blocked after this time frame. All trips of the NSST are for fault conditions except for sustained undervoltage on the 4KV bus or manual emergency trip. To allow a fast transfer initiated by undervoltage deviates from the assumption that NSST voltage is in synchronization with RSST voltage prior to the transfer occurring. Such a transfer could be out of synchronization with RSST power, possibly causing damage to electrical equipment connected to the 4KV bus. The modification blocks a fast transfer from occurring on an undervoltage trip of the NSST. The slow transfer scheme (which utilizes a synchronization check) is not affected by this modification.

-- Revision of electrical protective circuits such that, whenever switchyard breakers 15G-13T-2 and 15G-14T-2 are open, the main generator output breaker and the NSST supply breakers will trip causing a fast transfer to the RSST. This modification also prevents out of synchronization fast transfers from the NSST to the RSST.

The 15G breakers connect the main generator and NSST to respective offsite AC power sources. If both 15G breakers were to open at power levels below 40%, and the main generator breaker remained closed, the plant auxiliary buses would remain connected to the generator through the NSST supply breakers. The

resulting electrical transient would be an initial overvoltage and overfrequency followed by an exponential decay of these parameters during generator coastdown. During coastdown, several actions could result in a fast transfer to the RSST. In certain circumstances, this fast transfer would be out of synchronization in phase and voltage. This could damage the electrical loads connected to the auxiliary buses. The modification will initiate tripping of the generator output breaker and NSST supply breakers whenever both 15G breakers are open. Thus, during coastdown, the generator will not remain connected to the plant auxiliary buses.

The above modifications were made in response to a design inadequacy discovered by the licensee and detailed in Licensee Event Report (LER) 88-026.

-- Revision of the directional relays on the 4KV emergency buses such that the Emergency Diesel Generators (EDGs) can be exercised with either the NSST or RSST supplying plant loads.

The NSST supplies the emergency bus through a non-emergency bus and a tie breaker. The RSST supplies the emergency bus directly through its supply breaker. Reverse current flow from the emergency bus through the tie breaker is limited to 1120 amps by a directional overcurrent trip of the tie breaker. This trip is designed to protect the emergency bus and EDG from external faults when the EDG is in parallel with either the NSST or the RSST. With the RSST supplying plant loads (tie breaker closed, NSST supply breaker open) and the EDG in parallel, during normal operation the current flow through the tie breaker is greater than the 1120 ampere setpoint. The directional overcurrent trip will thus prevent exercising the EDG in parallel with the RSST even though no fault exists on the 4KV buses. This problem contributed to a plant trip which was described in LER 88-028.

The modified configuration will subtract current sensed at the RSST supply breaker from the directional overcurrent trip of the 4KV tie breaker. The trip setpoint of this modified parameter will remain at 1120 amps. In this fashion, the original design basis for the tie breaker reverse overcurrent trip will be maintained while accounting for current flow from the RSST. This will allow the EDG to be exercised in parallel with the RSST during normal operations.

-- Addition of a more sensitive high current detector for the 4KV emergency bus differential relays into the protective scheme. This change will provide the differential relays a uniform response time for all levels of fault current. Previously, the current sensing unit could sense all levels of fault current but was more sensitive to low level faults than to higher level

faults. The new current sensing unit provides added protection and sensitivity at high fault levels. The use of this unit was originally deleted because of seismic concerns. Subsequent licensee evaluation qualified the units for Unit 3 seismic design parameters.

The inspector reviewed the PDCR package for compliance with procedure ACP-QA-3.10. The inspector also reviewed the technical adequacy as well as the 10 CFR 50.59 Safety Assessment. No discrepancies were noted.

12.0 Refueling Operations (71707, 60710, 60705, 62703)

The inspector verified fuel movements within the reactor cavity and spent fuel building were conducted in accordance with Technical Specifications and Station Procedure EN 31007, "Refueling Operations." No significant personnel or procedural inadequacies were noted. A communications error of minor significance nearly resulted in violation of procedural requirements to maintain fuel building integrity during fuel movements in the spent fuel building. It was suggested to licensee management that stricter communication controls be considered during fuel movements in the spent fuel building.

A number of equipment failures or problems of minor or no safety significance were identified by the licensee during the refueling operations. Five Rod Cluster Control Assemblies (RCCAs) were replaced following Eddy Current Testing. Four RCCAs were rejected due to indications of rod guide wear. The fifth RCCA was rejected due to evidence of hafnium hydriding. All five RCCAs were replaced in accordance with PDCR-MP3-89-012.

Two fuel element defects were identified via ultrasonic test (UT) inspection. The licensee had detected indications of failed fuel elements during the previous cycle via isotopic analysis of coolant samples. These indications suggested there were very small leaks in a small number of "once burned" fuel elements. At no time during the cycle were technical specifications for coolant activity exceeded. All eighty-nine "once burned" fuel assemblies were UT inspected. Two assemblies were found to contain leaking elements. The two assemblies were located "corner to corner" to each other during the last cycle. For this reason, the licensee UT inspected the two, "twice burned" assemblies which had been adjacent to the leaking assemblies. Two other "twice burned" assemblies were UT inspected for unrelated reasons. No leaking elements were identified in these additional inspections. No other assemblies were UT inspected. Both leaking assemblies were replaced in the core.

The inspector discussed this finding with the Unit 3 Reactor Engineer and verified the licensee's actions were in accordance with PDCR MP3-89-012. The inspector also reviewed the coolant analysis trending for the previous cycle. With the exception of periods following plant trips, dose equivalent iodine (DEI) 131 levels remained at approximately 1.0E-02 uCi/gm. On

at least three occasions during the cycle, DEI levels approached, but did not exceed, the technical specification limit of 1.0 uCi/gm. These "spikes" were short lived. The inspector had no further questions.

A fuel assembly grid strap was found broken during the core offload. The broken segment was retrieved from the core area without incident. The licensee is designing a shield to allow removal and disposition of the strap. Preliminary indications suggest the strap was broken during the previous core load. This is based on observed oxidation on the fuel assembly where the strap should have been. Also, reload records from the last refueling outage revealed two under-load trips of the SIGMA refueling machine during reload of the affected fuel assembly. The licensee is continuing their analysis of the circumstances. The inspector has no further questions at this time.

Fuel movements were delayed for approximately 36 hours due to poor water clarity in both the spent fuel pit and reactor cavity. The poor water clarity interfered with the refueling apparatus operator's vision into the pool areas. Chemistry analysis confirmed the clarity problem was caused by iron oxide. The licensee suspects the iron oxide came from the "B" train of Residual Heat Removal (RHR) which had recently been restored to service following a period of dry layup and maintenance. The licensee restored pool clarity by using temporary filter skids and by increasing purification flow. The inspector had no further questions.

The inspector found the licensee's actions to address these technical problems to be adequate.

13.0 Maintenance

An NRC inspection team completed a programmatic review of the maintenance area for all Millstone units during the period of May 30 - June 16. The review was completed per the requirements of TI 2515/97 and the results are described in Inspection Report 50-423/89-80. Resident inspector observations and findings as part of that effort are provided in the Maintenance Team report.

The inspector observed and reviewed selected portions of preventive and corrective maintenance to verify compliance with regulations, use of administrative and maintenance procedures, compliance with codes and standards, proper QA/QC involvement, use of bypass jumpers and safety tags, personnel protection, and equipment alignment and retest. No inadequacies were identified.

13.1 MSIV Control Solenoid Seat Cracks

During the inspection and service of the MSIV 3MSS*CTV27B, the licensee discovered a small crack and a diminished height in the seat of control solenoid 3MSS*SV272B. This solenoid is one of two redundant solenoids that will deenergize to open and allow steam into the upper

piston chamber to close the MSIV. The two solenoids work in conjunction with two vent solenoids that must also close so that sufficient steam pressure will build in the upper piston chamber to close the main valve. Of the two redundant solenoids that allow steam into the upper piston chamber, only one is needed to provide enough steam to close the valve.

The solenoid valve seat is welded into a control block (manifold) and cannot readily be removed. Therefore, the licensee decided to repair the valve seat in place. Since the valve seat has been lapped in previous valve servicing, it has become necessary to build the solenoid valve seat up to maintain the valve stroke within its required limits. To build up the seat height, the licensee will be using an electrochemical metalizing process. The metalizing procedure can be found under special procedure 89-3-8. The process will be bonding a stronger nickel-based compound to the valve seat. The tensile strength of the bond is 12,000 psi which should be strong enough to resist any peeling. The metalizing process is not expected to fill the crack but will maintain the existing crack width and size. After completing the metalizing process, the valve seat will be lapped so that the valve disk has 100% contact seating while maintaining the required seat height. The metalizing process has been performed previously on a feedwater valve from Millstone Unit 1. Although this valve has not yet been disassembled for reexamination, the licensee has determined this type of repair to be permanent. As a follow-up, automatic work order AWO MP3-89-10096 will require a follow-up inspection and repair (if needed) to be performed at the next outage.

Although the crack will not be repaired by the metalizing process, the licensee has determined that the crack will have no adverse impact on the safety function of the MSIV (closure-isolation). The crack in the seat begins at the seat surface and extends down the length of the seat base. The crack in the seat face will allow steam to escape through the solenoid causing additional scoring in the valve seat and allowing steam to enter the upper piston chamber. With the vent valves (1A, 1B) open, the steam pressure in the upper piston chamber will not be sufficient to cause the MSIV to inadvertently close. Should the seat fail completely, a 9.5 mm built in orifice will restrict steam flow into the upper piston chamber. With the vents open and at a design operating pressure of 1185 psi, approximately 144 psi can be expected in the upper piston chamber. This is insufficient to cause the MSIV to close, thereby preventing inadvertent plant transients from resulting in a MSIV closure. Since the purpose of this solenoid is to allow steam into the upper piston chamber for MSIV closure, a failure of the solenoid seat will not prevent the MSIV from performing its designed safety function (closure-isolation). In addition, a second steam solenoid which performs the same function and offers redundancy in MSIV control.

Millstone has not experienced this type of seat cracking in the past. This valve is unique in the U.S. and Europe, and there is no history of seat failure to draw upon. The licensee and the manufacturer do not feel that this will be a recurring problem. The inspector had no further questions at this time.

During the MSIV inspection and servicing, the licensee discovered that the replacement check valve used in the control block had cracks in its machined surfaces. Since the licensee has additional replacement check valves, this discovery will not affect the operation of the MSIV at this time. However, the licensee will be looking into the quality control implications of this discovery. A single defective check valve would not affect the safety function of the MSIV (closure-isolation). There are two separate trains (control blocks) of control solenoids that control MSIV operation, with two check valves in each. The check valves maintain a working steam pressure in the control blocks during a main steam line break (upstream or downstream). In order for the MSIV not to close, a similarly positioned check valve from each train would have to fail. The licensee and the manufacturer believe that the probability of failure of two similarly placed check valves is small. This fact, coupled with the thoroughness of the mechanics installing the replacement parts, suggests that the probability of adversely affecting MSIV operation will be small. The inspector agreed but suggested a follow-up in the quality control area and perhaps a check valve installation procedural modification to ensure that new components are carefully examined.

No inadequacies were identified in licensee actions to perform valve maintenance, and to identify and correct discrepancies.

13.2 MSS Safety Valve Setpoint Drift

Plant Incident Report 73-89 dated 5/17/89, documented setpoint drift problems with 14 of 20 Main Steam Safety valves. The problem was identified during a routine surveillance test to check the setpoint of the installed valves. Technical specifications allow a +/-1% tolerance in the acceptance criteria for the test. Ten of the safety valves exceeded their setpoint by greater than 1%. One of these exceeded the allowable setpoint by more than 3%. The remaining failures were greater than 1% below their allowable setpoint. Thirteen of the 14 safeties were reset within the +/-1% tolerance. Three of the fourteen valves required an adjustment after the initial retest. These three valves are to be replaced by the licensee. The removed valves will be examined by the vendor (Crosby).

MSS setpoint drift has been a recurring problem at Millstone Unit 3. Licensee Event Report (LER) 87-36-00 documented setpoint drift on 11 MSS valves. The licensee suspects high drift is caused by sticking

between the valve disc and seat during the first lift. This is suggested by the generally higher initial lift value for the first lift. Low setpoint drift may be caused by spring relaxation over extended periods of time at elevated temperatures.

The as-found lift settings in May 1989 did not have adverse safety implications: licensee evaluation concluded the valves lifted within the low pressure bounds analyzed for a steam generator tube rupture incident, and within the high pressure bounds of the main steam system design.

The licensee is considering a design change to expand the setpoint tolerance to +/-3%. This will require a change to technical specifications and a boiler code exception. The licensee does not intend to submit this change before the end of this outage. The inspector had no further questions.

13.3 Loop Isolation Valve Body-Bonnet Leakage

The licensee has discovered that 7 of the 8 main loop isolation valves (LIV's) show indications of leakage at the body to bonnet joint. The leakage appears to be small; however, leakage at the hot leg valves was more severe based on greater boric acid deposits and contamination levels. The licensee had previously repaired body to bonnet leakage on the "A" and "B" hot leg valves in April 1988 and February 1989. Both these valves show evidence of continued leakage. The root cause of the chronic leakage is unknown at this time.

The discovery of this problem has added a significant workload to the outage. The licensee had originally intended to lower vessel level to mid-loop for check valve inspections. LIV work will extend mid-loop operations about 3 days.

The licensee is evaluating alternative solutions to correct the problem. These alternatives include a stud stretch evaluation, and/or replacement of the body to bonnet gasket with upgraded Flexicarb gasket materials. The licensee might choose to forego repairs on certain of the valves. The leakage is not considered pressure boundary leakage and, as such, can continue without violating technical specifications. (Identified and unidentified leakage rates during the cycle were minimal.) The licensee does intend to perform extensive inspection of one hot leg valve to determine a root cause for the leakage. The inspector will continue to monitor the licensee's activities to resolve this issue.

13.4 Accumulator Level Indications Out of Calibration

Seven of eight Safety Injection Accumulator level transmitters were found out of calibration during surveillance testing. The detectors are Barton capillary D/P cells with capillary bellows seals separating the process fluid from the detector. Accumulator tank level is

used to verify compliance with TS 3.5.1, which specifies a level band. Each of the four accumulators has two redundant level indicators. A plant incident report (PIR) was written to document the failures.

Five level instruments were found reading higher than actual; two read lower than actual. Two accumulator tanks had both level instruments reading higher than actual (Tanks "B" and "C"). Tank "A" had diverging errors in both instruments and tank "D" had one instrument reading low with the other reading within specification. The licensee is researching operator logs of accumulator tank levels during the last cycle to determine if, given the error as found, the accumulators may have been inoperable during the cycle. PIR 3-89-90 tracks completion of licensee review of this issue, which will determine the impact on plant safety from operating with the transmitter errors. This item is unresolved pending completion of the licensee's review and subsequent review by the NRC (UNR 89-08-02).

These level detectors were found out of calibration during the last refueling outage. The licensee suspects a design problem with the detectors and/or their sensing configuration. The licensee is investigating possible design modifications or operational compensations. It is not anticipated that the licensee will take actions to modify the indicators during this outage. The licensee may however, change the alarm setpoints to compensate for anticipated errors through the next cycle. The inspector had no further questions.

13.5 Litton-Veam Connectors

Litton-Veam connectors are used at Millstone Unit 3 to provide an environmentally qualified barrier between an instrument's electrical connections and the exterior environment. The qualification testing for the Litton-Veam connector is documented in NUSCO Test Reports No. 558-1657A and 1657B. Inspection Report 88-04 describes prior NRC review of this area.

A review of Litton-Veam connector installations indicated that 21 connectors were installed without heat shrink tubing over the conductor/pin interface (see PIR 060-88) and thus were not environmentally qualified. Of the 21 installations, only 4 are required to be environmentally qualified per 10 CFR 50.49. An additional 41 Litton-Veam connectors were identified with potential IR leakage problems, within the connector, when exposed to the postulated accident environment. Of these 41 connectors, the licensee determined that 27 were required to be qualified under 10 CFR 50.49. Based on the above, a total of 31 Litton-Veam connectors were scheduled for replacement during the refueling outage.

The inspector viewed the replacement of two Litton-Veam connectors with Rosemount connectors (3RCS*PT49 and 50). The work packages were well prepared and contained installation directions from both Rosemount (Manual 4498, Revision D0) and the licensee. Installation personnel were found to be knowledgeable concerning the installation requirements. The installation included appropriate quality inspector coverage for critical elements.

One error in the installation acceptance criteria was identified by the NRC inspector. The minimum bend radius for the connector seal cable was established as greater than 1/2 inch by the installation instructions. The acceptance criteria for the bend radius, in the inspection plan, was given as "Not greater than 1/2 inch." After a discussion with the licensee, the acceptance criteria for bend radius was corrected to be "Not less than 1/2 inch." The same error was subsequently corrected in a number of Litton-Veam replacement work packages.

Inspector review of this matter with licensee personnel noted that the error did not result in incorrect installation since workers were knowledgeable of the correct acceptance criteria. The inspector had no further questions in this area.

14.0 Surveillance (61726)

The inspector observed portions of surveillance tests to assess performance in accordance with approved procedures and Limiting Conditions of Operation, removal and restoration of equipment, and deficiency review and resolution. The inspector monitored surveillance activities associated with the "B" Train, Engineered Safety Feature (ESF). The specific procedures were:

-- SP 3646A.11, "B EDG Full Load Rejection"
-- SP 3646A.20, "EDG Partial Load Reject"
-- SP 3646A.16, "Train B Loss of Power Test"
-- SP 3646A.18, "Train B ESF with LOP"

The inspector monitored preparations for the train "B" LOP (loss of offsite power) test performed on June 1, 1989. These preparations included system lineups, verifications, prerequisite performance, and pre-surveillance briefing. The inspector observed control room operations during de-energization of the "B" 4KV emergency bus. No personnel or procedural inadequacies were noted.

Several component failures and test exceptions were noted. The failures were minor in nature and the inspector verified that Trouble Reports (TRs) were initiated for each failed component. A Plant Incident Report (PIR) was also initiated to document the failed components. The test exceptions were components which were inoperable at the time of surveillance due to maintenance. Both test exceptions and failures were properly listed in

the surveillance test acceptance criteria verification appendix. These will need to be retested before returning the facility to mode 4. The retests are not expected to require performance of the LOP surveillance. Retesting of the failures is positively controlled through the TR, AWO, and PIR programs. Test exceptions are tracked in a less formal manner. The Operations Assistant is solely responsible for tracking retest of test exceptions. The inspector found this practice acceptable but suggested that a more formal method be developed to track test exceptions to ensure surveillance activities are completed.

The inspector reviewed the remaining completed surveillance procedures. Test failures and exceptions were minor in significance and were properly documented on TRs in the acceptance criteria verification appendices. The inspector had no further questions.

No inadequacies were noted.

15.0 Review of Licensee Event Reports (LERs)

Licensee Event Report (LER) 88-26-01 was reviewed to assess LER accuracy, the adequacy of corrective actions, compliance with 10 CFR 50.73 reporting requirements, and to determine if there were generic implications or if further information was required. Selected corrective actions were reviewed for implementation and thoroughness. Licensee corrective actions for design deficiencies identified in the LER are discussed further in Section 11.2 above. The inspector had no further questions.

16.0 Management Meetings

Periodic meetings were held with station management to discuss inspection findings during the inspection period. A summary of findings was also discussed at the conclusion of the inspection. No proprietary information was covered within the scope of the inspection. No written material was given to the licensee during the inspection period.