U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.: 50-293

Report No.: 50-293/88-37

Licensee: Boston Edison Company
800 Boylston Street
Boston, Massachusetts 02199

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: December 27, 1988 - February 5, 1989

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<u>Inspection Summary</u>:

<u>Areas Inspected</u>: Restart Staff inspection to assess licensee management controls, conduct of operations, and startup testing activities during the initial phase of the licensee's Power Ascension Program. A review of the licensee's preparations for startup was also performed on December 27-30, 1988.

<u>Results</u>:

<u>Violation</u>: The report documents a licensee-identified violation involving failure to control locked high radiation area access as required by the Technical Specifications (Section 8).

<u>Unresolved Item</u>: Further review of the licensee's newly generated Radiological Environmental Technical Specifications (RETS) surveillance implementing procedures for technical adequacy, as well as review of the licensee's approach to event reporting is needed to determine adequacy (Section 5.0).

<u>Strengths</u>:

1. Licensee management provided active and effective oversight and assessment of plant operations (Section 11.0);

2. Operational evolutions were performed in a competent and professional manner (Section 3.0);

3. Startup testing activities were well controlled (Section 4.0);

4. The licensee's design change which corrected the secondary containment truck lock deficiency was implemented in a timely manner and was well thought out from conception to implementation (Section 7.0).

<u>Weaknesses</u>:

1. The licensee experienced difficulties with implementing the torus vacuum breaker block valve modification due in part to an overly aggressive implementation schedule set by upper management. Further, weak organizational communications prevented upper management from recognizing the operating constraints imposed as a result of the initially implemented torus vacuum breaker block valve modifications (Section 7.0);

2. A lack of formal administrative controls for the scheduling and performance of RETS surveillances caused failure to properly implement RETS (Section 5.0).

Observation

The operations staff experienced some difficulties in transition from an extended outage to the operating mode. In these instances, licensee staff response and management oversight provided for appropriate identification, assessment and implementation of corrective actions (Section 3.0).

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DETAILS

1.0 Summary of Facility Activities

On December 21, 1988, the NRC Commissioners voted unanimously to endorse the NRC staff's proposal to permit the licensee to restart the Pilgrim Nuclear Power Station. On December 30, 1988, Mr. William T. Russell, the Regional Administrator for Region I, approved the NRC Restart Assessment Panel's recommendation to release the licensee from the first Power Ascension Program approval point (initial criticality to 5% rated power). The program includes NRC Regional Administrator approval points at 5%, 25%, 50%, and 75% of full power, as well as a licensee written report and NRC review after completion of testing at full power.

On December 30, 1988, at 9:54 p.m., the Pilgrim reactor achieved criticality. Due to neutron monitoring system problems the licensee began a controlled shutdown at 10:14 p.m. the same day and placed the reactor in cold shutdown condition. The licensee replaced failed intermediate range neutron monitoring detectors and the plant returned to criticality at 5:05 p.m. on January 2, 1989. The licensee subsequently conducted reactivity manipulation training in order to satisfy NRC requirements for the reactor operators with conditional licenses.

Following reactor heatup and pressurization to 150 psig, the licensee successfully completed Reactor Core Isolation Cooling (RCIC) and High Pressure Core Injection (HPCI) system flow tests. On January 10, 1989, the licensee commenced a controlled reactor shutdown after determining that the torus to reactor building vacuum breaker block valves may not perform their containment isolation function following a seismic event. The reactor was brought subcritical at 9:10 p.m. and reached cold shutdown at 2:15 a.m. on January 11, 1989.

The licensee commenced reactor startup on January 27, 1989, following modifications to the air supply and accumulators for the vacuum breaker block valves. During a subsequent surveillance on the air supply, the valves were again declared inoperable due to increased air leakage. In accordance with the Technical Specifications, the licensee commenced a reactor shutdown at 9:55 p.m. January 27, 1989, and an Unusual Event (UE) was declared. The reactor was subcritical at 10:15 p.m. and the UE was terminated at the same time. The plant remained in cold shutdown for the remainder of this report period while the licensee performed additional modifications and repairs to the air supply system.

NRC inspection activities during this report period began with forming the onsite Pilgrim Restart Staff led by Mr. Clay C. Warren, Senior Resident Inspector and Restart Manager. The Pilgrim Restart Staff is composed of the Pilgrim resident inspectors, resident inspectors from other plants, NRC regional-based and headquarters-based inspectors and an NRC contractor. During the week of December 27, 1988, the inspectors performed startup inspections. On December 29, 1988, the Pilgrim Restart Staff implemented 24-hour shift coverage. This coverage was reduced to extended day shift coverage at times, consistent with reduced testing activity and plant shutdown. A representative from the Commonwealth of Massachusetts was onsite on December 29 and 30, 1988, and on January 2, 1989 to observe the NRC Restart Staff activities.

2.0 Restart Preparation Activities

The Restart Staff monitored the licensee's preparations for startup activities on December 27-30, 1988. Emphasis was placed on recent status changes (i.e., additions, deletions, priority changes, revisions) since the last NRC review, documented in Inspection Report 50-293/88-33. The purpose was to verify that new items and changes had been appropriately dispositioned and that the overall status was acceptable to support safe restart of the facility. The review included safety system valve lineups, outstanding quality assurance discrepancy reports, maintenance requests, safety evaluations and engineering service requests. The status of licensee actions on outstanding NRC Bulletins and 10 CFR Part 21 reports was also assessed.

2.1 Review of Active Temporary Procedures

Internal licensee memorandum (PM 88-229), "Final Review of Generic Issues from Restart Checklist #6," Item 6.B.02.723, directed licensee division managers to review outstanding Temporary Procedures (TP) to determine their potential impact on startup. Included in the review was the evaluation of potential adverse operational consequences of installed jumpers, lifted leads and off-normal system alignments resulting from partially accomplished TP's. This item has been updated on a continual basis by individual divisions and periodically by the Operations Review Committee (ORC) for several months. The inspector reviewed the TP index with each responsible division manager and verified completed TP's were being retired, or as appropriate converted to permanent station procedures. No partially completed TP's were identified. The inspector also noted that active TPs were properly tracked. Licensee actions with respect to TP status review were timely and thorough.

2.2 Review of Safety Evaluations

The inspector reviewed open safety evaluations which were projected to be active during the restart. The open safety evaluations were of sufficient technical detail and adequately addressed 10 CFR 50.59 evaluation criteria. The inspector had no further questions with regard to active safety evaluations. However, the inspector expressed concern to the licensee with respect to the use of "conditional" safety evaluations. The licensee had routinely placed conditions or limitations on the applicability of safety evaluations. The conditions were typically conservatisms directed by the ORC in the form of operational limitations, compensatory personnel actions or increased surveillance testing of affected components. The inspector informed the licensee that a safety evaluation should be a definitive analysis of a plant condition with respect to its design basis as described in Technical Specifications (TS) and the Final Safety Analysis Report (FSAR). If the existing condition is evaluated not to be within the design basis for all applicable modes of operations then appropriate regulatory relief such as proposed TS changes, FSAR revision, justification for continued operation or temporary waiver of compliance must be initiated. The licensee concurred with this position and committed to not invoke "conditional" safety evaluations and to revise procedures as appropriate. It should be noted that no active safety evaluations had conditional limitations. The licensee issued an engineering department memo to reinforce this commitment. An additional followup will be conducted in this area under an existing outstanding item (87-45-04) which addresses the licensee's use of FSAR Appendix G for the determination of conditional system operability.

2.3 Temporary and Permanent Radiological Shielding Program

The inspector reviewed the licensee's program for the evaluation, installation, periodic inspection and material control of temporary and permanent radiological shielding. The shielding program is implemented by the Radiological Technical Support Division (RTSD) in accordance with PNPS Procedure 6.10-008, "Installation and Removal of Shielding." A recent Quality Assurance Department (QAD) surveillance (88-2.1-39) of the shielding program revealed a procedural deficiency, in that the permanent shielding request form and the permanent shielding log were not included as attachments to Revision 1 of Procedure 6.10-008. The inspector performed a plant walkdown of permanent and temporary shielding installations and reviewed shielding records and determined all installed shielding had been properly requested, logged and implemented irrespective of the procedural deficiency. Revision 2 to Procedure 6.10-008, which incorporated corrective actions to the QAD deficiency, was approved by ORC and was being prepared for distribution at the conclusion of the inspection period. The revised procedure effectively developed the necessary direction and accountability to ensure continued positive control of the shielding program. The RTSD personnel responsible for the implementation of the program were well versed in the procedural enhancements of Revision 2 to Procedure 6.10-008 and were in the process of upgrading shielding logs to facilitate a smooth transition to the revised procedure upon issuance.

2.4 Engineering Service Requests

Engineering Service Requests (ESR) are used by any person within the nuclear organization and sent to the Nuclear Engineering Department to request engineering or technical support.

The inspector reviewed a listing of ESR's opened since the last NRC review. The inspector discussed various ESR's with appropriate management personnel to determine their potential impact on the plant restart. Two levels of management review are utilized to identify those ESR's which could affect restart of the plant. These two levels of management review appear to be effective. Engineering section managers were knowledgeable of the contents of the ESRs and the determinations made with respect to their potential affect on plant restart. The inspector had no further questions.

2.5 Quality Assurance Discrepancy Reports

The inspector reviewed selected outstanding quality assurance (QA) audit and surveillance reports. These included deficiency reports (DR), non-conformance reports (NCR) and potential condition adverse to quality (PCAQ) reports. These reports were reviewed to determine if the licensee had appropriately identified those items requiring licensee attention and action prior to restart.

The Potential Condition Adverse to Quality (PCAQ) report is issued to resolve suspected or actual conditions adverse to quality identified by the departments not using other Quality Assurance discrepancy reports, and to identify actual or suspected failures to comply with NRC rules and regulations or the facility license. The inspector reviewed PCAQ's opened since the NRC's last review and identified no restart concerns.

Deficiency reports are issued by the Quality Assurance (QA) Department during the conduct of audits and surveillances for conditions contrary to management policies and procedures, regulatory requirements or licensee commitments. The deficiency status report as of December 26, 1989, listed eight open DR's, two of which were considered to be required to be dispositioned. These two DR's were properly dispositioned prior to startup. No restart concerns were identified with respect to the remaining open DR's. Review of a sampling of recently closed DR's indicated appropriate corrective actions were taken to correct the problem and prevent recurrence. Good followup was performed by the person originating the DR to ensure the corrective actions had been taken.

Nonconformance reports are used by operations quality control personnel to document and report nonconforming materials, parts or components identified as a result of receipt, installation and other inspections. Review of NCR's showed only four open NCR's. These NCRs were written against items not installed and therefore, will not affect restart activities. No discrepancies were identified.

2.6 Failure and Malfunction Reports

The failure and malfunction report (F&MR) is used to document and evaluate failures, malfunctions and abnormal operating events. The inspector's review of F&MR's identified no additional items requiring licensee action prior to restart.

The inspector also reviewed the licensee's methods of corrective action, root cause determination and item closeout. The inspector determined that the licensee had a good understanding of the root cause and appropriate actions were taken. The inspector had no further questions in this area.

2.7 10 CFR Part 21 Report by Limitorque Concerning Elevated Ambient Temperature Effects on RH Insulated DC Motors

On November 3, 1988, Limitorque Corporation informed the licensee of the issuance of a 10 CFR Part 21 notification concerning elevated ambient temperature effects on RH insulated DC motors. Limitorque determined that in some cases SMB valve actuators with RH insulated motors may not develop full rated starting torque at elevated ambient temperatures, due to resultant DC motor resistance increases. Limitorque recommended that the licensee review their DC motor operated valves to determine if any of the listed RH insulated DC motors were required to operate at ambient temperatures above those specified in the Part 21. Limitorque also requested that the licensee identify the order number and serial number from the actuator nameplate, the maximum ambient temperature and valve requirement. Limitorque also noted that they have had no reported failures as a result of this phenomenon.

The licensee reviewed their records on SMB valve actuators with RH insulated DC motors installed in safety-related applications and determined that two motor-operated valves (MOV) fit the vendor's screening criteria. These two valves were 2301-5 (HPCI steam line isolation valve) and 2301-8 (HPCI injection line). The licensee forwarded the information to Limitorque, and requested an analysis be performed to determine if the two DC MOV's would operate properly in the high temperature environments described in an attached temperature profile for each valve. Likewise, BECo also requested an evaluation of operation of the valves at less than rated voltage during the high temperature conditions. As of December 30, 1988, the licensee had received verbal confirmation from Limitorque that the reported problem did not apply to the referenced motor operated valves. Based on this, the inspector concluded that the requirements of this Part 21 would not affect plant startup.

2.8 Review of Maintenance Requests

The licensee's Work Prioritization Review Team (WPRT) meets daily to assign priority to each Maintenance Request (MR) and is composed of representatives of various station groups, including maintenance, operations, outage management, construction management and fire protection. The inspector attended a WPRT meeting on December 28, 1988. Ten MR's were reviewed, two were identified as restart MR's and work was properly completed prior to startup.

The inspector also reviewed the current list of outstanding MR's to ensure that they had been properly prioritized and scheduled. Two MR's which had been designated as non-startup items addressed deficiencies in the emergency lighting system. The emergency lights are needed in order to facilitate operator actions to perform safe shutdown from outside the control room in the event of a loss-of-station power. After questioning by the inspector, these two MR's were upgraded for completion prior to plant startup.

Repairs to the emergency lights had been delayed due to the lack of spare parts for the units. Seven emergency lighting units were determined by the licensee to be inoperable. A subsequent walkdown of the inoperable lighting units by the licensee demonstrated five of the emergency lights were supported by adjacent or near vicinity lights. The inspector considered this acceptable to meet the intent of emergency lighting. The two remaining inoperable units were used to illuminate stairways leading to the safe shutdown panels, and were determined by the licensee to be necessary for plant startup. These two emergency lighting units were repaired prior to plant startup.

After identification of the misprioritized MRs the licensee aggressively pursued the repair of the emergency lighting units. The inspector concluded that the required lighting units were operational prior to startup.

With the exception of the MR's associated with emerging lighting, the inspector concluded that the licensee had properly prioritized outstanding maintenance activities to support initial plant operations.

2.9 Surveillance Program Status

The licensee tracks the surveillance program status as detailed in Procedure No. 1.8, "Master Surveillance Tracking Program (MSTP)". Elements tracked include a listing of all scheduled surveillances, windows of opportunity to perform tests and methods to identify late and missed surveillance procedures to management for increased visibility and corrective actions.

The inspector reviewed the licensee's MSTP and evaluated a sample of technical specification surveillance requirements to determine if they were in agreement with the MSTP. No discrepancies were identified.

2.10 Safety System Walkdowns

In assessing the plant's readiness for return to power operations, a review of emergency core cooling system valve lineups was performed. A review of the licensee's current completed valve lineup for the low pressure coolant injection system and high pressure coolant injection system was performed. In addition, the inspector completed a walkdown and verification of selected valves in each system. This was performed with the aid of a nuclear plant operator who physically checked system valves for the inspector during the walkdown. No discrepancies were noted

2.11 Lifted Lead and Jumper Log

Electrical lifted leads and jumpers at the station are controlled by temporary modifications, maintenance requests and station procedures. Due to the various approved methods of performing lifted leads and jumpers, a central tracking system is used to allow an operator to quickly assess status at a given time. The inspector reviewed the licensee's lifted lead and jumper log as well as the licensee's controlling procedure 1.5.9.1, "Lifted Leads and Jumpers" to ensure compliance with the procedure. Lifted leads and jumpers were noted to be placed in accordance with procedural requirements and documented in the log. No discrepancies were identified.

2.12 Operations Review Committee (ORC) Activities

The inspector reviewed recent ORC meeting minutes, interviewed the ORC Chairman regarding ORC restart readiness reviews and attended an ORC meeting on December 28, 1988. The committee appeared to be functioning acceptably to support plant restart.

3.0 Operations

3.1 Sustained Control Room Observations

Based on over 500 hours of around-the-clock on-shift observations during December 29 - February 5, 1989, the inspectors determined that control room activities were conducted in a professional manner. Communications in the control room were clear and formal. Operators typically repeated back instructions which assured their understanding of the instructions. The flow of information among shift personnel was good, such that all members were aware of plant status and planned evolutions. Shift turnovers were conducted in a formal manner. Appropriate information about system status and work in progress was conveyed to the on-coming shift through individual operator turnovers and pre-shift briefings. The pre-shift briefing by the offgoing Watch Engineer covered encountered problems and upcoming evolutions in sufficient detail as to keep the on-coming personnel abreast of overall plant status. Attendance at these briefings was consistent and included representatives from Chemistry, Health Physics, and Outage Management groups.

Shift staffing level has been adequate. The licensee has staffed a four-shift rotation with three senior reactor operators (SROs) and two reactor operators (ROs) per shift. Addition of an extra SRO to each shift appears to have strengthened the shift organization with added experience. Currently, only 8 ROs have unrestricted licenses since the 13 newly licensed ROs are performing limited licensed duties, pending completion of on-watch training and reactivity manipulations to be conducted during the power ascension program. At an appropriate point after restart, the licensee intends to implement a six-shift rotation of two SROs and 2 ROs per shift. There are also sufficient non-licensed equipment operators to staff six shifts.

The control room operators were attentive to their panels, alarms and indications. Response to alarms and system parameter trends was appropriate. Operators were familiar with normal, abnormal and alarm response procedures and utilized them appropriately. The control room staff generally exhibited a safety conscious and conservative attitude. The Technical Specifications (TS) were conservatively applied. Administrative requirements were generally met.

The inspectors noted that the operations staff experienced some difficulties in transition from an extended outage to the operating mode. On occasions, the control room operators and supervisors were slow in developing a questioning attitude, especially concerning equipment status. In certain cases, the on-shift personnel in the control room did not know the reason for equipment being out of service or the status of maintenance work on the equipment. On January 4, 1989, with the reactor critical and primary containment integrity required, an oxygen analyzer sample line containment isolation valve failed a surveillance test. The licensee delayed taking the action required by TS 3.7.A.2.b for failed containment isolation valves for 2 hours until prompted by the inspector. While no time limit for initiation of action to close the redundant valve in the penetration is included in the TS, this 2 hour delay was not warranted. Subsequent troubleshooting by the licensee revealed that the problem was the valve indication only. The inspector discussed this event with licensee management and the licensee committed to emphasize a conservative approach to determination of equipment operability, and to instruct the operators that required actions should typically be taken within 30 minutes unless Technical Specifications specify a longer time.

The inspectors routinely reviewed various control room logs including the Limiting Condition for Operations (LCO) Log, the disabled Annunciator Alarm Log, the Operations Supervisor Log the Reactor Operators Log, the Lifted Lead and Jumper Log, and the Component Leak Log. The inspectors noted that items were properly logged and tracked. On occasions however, that control room operator logs were imprecise and activities such as those given in procedure 1.3.34 "Conduct of Operations" Section D were not always recorded. For example, a one hour technical specification action was identified and it could not be ascertained by the shift inspector when the action was satisfied. At the prompting of the inspector the licensee made a late entry to identify when the action was taken. Licensee management was informed of the noted weaknesses and has committed to review and take corrective actions.

Control room operators received good support from the shift technical advisors (STA) and administrative assistants. The STAs were used in developing failure and malfunction reports and maintaining various control room logs updated. The administrative assistants do much of the administrative paperwork and help to reduce traffic in the control room.

Operations management, including the Chief Operating Engineer and Operations Section Manager provided effective oversight of operations. Operations management was observed touring the control room frequently and discussing plant status and evolutions with the Watch Engineer.

3.2 Plant Tour Observation:

The inspectors made frequent plant tours and noted that the overall material condition of rooms and equipment remained excellent during the report period. Component labeling and tagging was good. The licensee personnel interviewed during the tours (HP, security, operations, contractor) had experience in their positions and were knowledgeable about their work and duties. HPs were cognizant of work activities in progress. Housekeeping controls were being maintained during work in progress.

During a tour of the reactor building 23 foot elevation, the inspector identified six reactor scram valve position switches which appeared misaligned. The scram valve position switches illuminate scram lights on control room panel C905. The scram lights are a backup indication to the operators of a scram and therefore do not serve any safety function. The licensee reviewed this finding and generated maintenance requests to correct the switch alignments.

On December 29, 1988, Mr. William T. Russell, Regional Administrator, Region I, toured the Pilgrim Station. Mr. Russell was accompanied by the Plant Manager, the Chief Operating Engineer and the resident inspector. Attachment II of this inspection report lists the items identified during the tour and the licensee's resolution of these items.

3.3 Review of Training Reactivity Manipulations

Currently, there are 13 reactor operators (ROs) and a senior reactor operator(SRO) whose licenses are restricted to cold shutdown condition. To obtain unrestricted operating licenses, these individuals are required to perform five significant control manipulations which affect reactivity or power level per 10 CFR 55.3(a)(5). They also have to stand training watches for at least one month at equal to or greater than 20% rated power.

Shortly after reaching criticality on January 2, 1989, the licensee conducted training criticals for the 13 ROs in order to partially satisfy the control manipulations requirement. The licensee prepared Temporary Procedure TP 88-89, "Reactivity Manipulations", to provide a description of indication and technique for the approach to criticality and return to subcritical operation.

The procedure required insertion of 45 in-sequence control rod drive notches between criticals which would preclude inadvertent criticality due to moderator temperature decrease. The training manipulations per TP 88-89 were observed by shift inspectors. Each trainee was under direct supervision of an SRO. A shift training coordinator was also present in the control room during the training to assist the operators. The inspectors determined that the procedure was well developed and training activities were performed in a controlled manner.

3.4 Cold Weather Protection

An inspection was conducted on January 5, 1989, to determine if the licensee had taken adequate measures to protect systems important to safety from extreme cold weather conditions to ensure operability. The inspector verified the presence and operability of heat tracing space heaters, and insulation.

A walkdown of selected systems indicated that the licensee had taken adequate measures with the exception of the diesel-driven fire water pump room. The space heater in the room was inoperable. This room is located inside the screenhouse and contains the diesel driven fire water pump, its associated starting batteries, and portions of the main fire water header. The licensee placed an additional space heater in the room in response to the inspector's finding.

On the same day, a fire sprinkler pipe froze due to the extreme cold weather and burst causing approximately one thousand gallons of water to drain within the condenser retube building. The condenser retube building was used to support the main condenser tube replacement work during a previous outage. The licensee's radiological survey results indicated that there was no spread of contamination within the building. The condenser retube building floor drains were collected in the miscellaneous radwaste tanks for processing. There were no releases to the environment and no personnel contaminations. The licensee subsequently replaced the damaged portions of the fire sprinkler system.

Generally the licensee's program to protect against the effects of cold weather conditions was found to be acceptable.

3.5 Review of Plant Events

Rod Block Not Occurring During Testing

On January 9, 1989, the licensee identified a problem concerning intermediate range monitor (IRM) wiring that effectively bypassed the source range monitor (SRM) "inoperable" and "upscale high" rod block functions for "A" and "C" SRM's. The reactor was in the startup mode with reactor pressure at about 140 psig at the time. During performance of a functional check of SRM's "A" and "C" per procedure 8.M.2-3.3, "Source Range Monitor", the licensee determined that the upscale trip and inoperative trip signals generated for the checks did not result in a rod block. At the time, IRM's "A", "C" and "E" associated with SRM's "A" and "C" for the rod block function were on range 8 and IRM "G" was on range 7. This configuration should have generated a rod block since IRM "G" was on range 7, but it did not. The primary purpose of the rod block is to ensure that the correct range of neutron instrumentation is in service.

Subsequent investigation by the licensee revealed that a wiring error associated with one of two rod block circuits of the reactor manual control system (RMCS) caused the failure. The wiring error bypassed two SRM's ("A" and "C") for the RMCS rod block function when IRM's "A" and "E" were on range 8 regardless of IRM's "C" and/or "G" range scales. This resulted in the licensee not fully complying with TS limiting condition for operation 3.2.C regarding the required degree of instrument redundancy during certain very limited startup modes of operation since the initial plant operation. The other rod block circuit was not affected by the wiring error. TS Table 3.2.C-1 identifies the minimum number of operable SRM's as three. Per TS the licensee placed SRM "D" mode switch to the STANDBY position thereby initiating a rod block. A Failure and Malfunction Report was initiated to document the problem.

The licensee determined the cause for the wiring error to be a personnel error during original plant construction in that the wires were reversed during installation. Review of original plant drawings by the licensee showed the currently prescribed termination points to be correct, and similar wiring associated with the other rod block circuit was visually inspected with no discrepancies noted. The deficiently wired channel was corrected and the SRM functional test was subsequently performed with satisfactory results. The inspector reviewed licensee actions associated with this event and determined that appropriate investigation and corrective actions had been taken. The licensee promptly identified the reason for the failure to obtain the rod block, the cause of the error and verified that that no other discrepancies existed. The inspector had no further questions.

Secondary Containment Isolation During a Surveillance Test

At 4:20 p.m. on January 15, 1989, the licensee experienced a secondary containment isolation and an inadvertent actuation of the "A" standby gas treatment system (SBGT). The actuation occurred during the performance of surveillance procedure 8.M.2-1.5.8.1, "High Drywell Pressure, Low Water Level and High Radiation Logic System A-Inboard Functional Test". The licensee's investigation revealed that during the performance of this surveillance test, the licensed operator inadvertently turned the keylocked control switch, "Rx Bldg HVAC Iso Test Channel A" to the TEST position (to the right) instead of placing the switch to the TEST LOGIC position (to the left) as instructed by Step 11 of the procedure.

The secondary containment isolation was reset and the "A" SBGT system was restored to normal standby status. The licensee secured further performance of the test, conducted a critique and issued a failure and malfunction report. The critique identified that human factors contributing to the error were the location of the control switch (height of switch is approximately seven inches above floor level), and the control switch terminology. The surveillance test was successfully completed later that day. This event was reported to the NRC via ENS at 5:10 p.m. The inspector had no further questions.

Plant Shutdown and Notification of Unusual Event Due to Inoperable Vacuum Breaker Block Valves

At 10:10 p.m. on January 27, 1989, the licensee declared an Unusual Event (UE) due to the initiation of a plant shutdown required by the Technical Specifications. After plant startup on January 27, 1989, reviews of the routine air supply surveillance data for the torus vacuum breaker block valve accumulators indicated increased leakage above the licensee-established limits. Due to this increased leakage, the licensee declared the vacuum breaker block valves inoperable and commenced a plant shutdown at 9:55 p.m. The reactor was brought subcritical at 10:15 p.m. on January 27, 1989 and the UE terminated at that time. Detail review of the problems associated with the vacuum breaker block valves and the plant shutdown/UE are discussed in Section 7.2 of this report.

4.0 Startup Testing Activities

4.1 Shutdown Margin Calculations

Technical Specification 4.3.A.1 requires that a sufficient shutdown margin be demonstrated following a refueling outage. To determine the shutdown margin (SDM), the licensee used Procedure 9.16.1, "In-Sequence Critical for Shutdown Margin Demonstration". The inspector reviewed the results of the procedure conducted during the initial reactor startup. The test consisted of accurately determining the reactor period during initial criticality and monitoring recirculation suction temperature. The SDM was then calculated by using the test data and various reactivity values and correction factors in the General Electric Cycle Management Report. Review of the test data and calculation indicated that the test was correctly performed and more than adequate SDM was present. The inspector had no further questions.

4.2 HPCI and RCIC Surveillance Testing at 150 PSIG

Technical Specifications (TS) require that the high pressure coolant injection (HPCI) system and the reactor core isolation cooling (RCIC) system be operable prior to exceeding 150 psig. To verify operability of HPCI and RCIC, the licensee planned to perform manually initiated full flow rate tests in accordance with station procedures PNPS 8.5.4.3 and 8.5.5.3. These procedures required that HPCI and RCIC be manually started and reach rated flow.

The inspector determined that the procedures as written did not completely verify the operability of these systems at 150 psig in that their initiating logic was not tested, nor was the time to reach rated flow and pressure measured. After this concern was discussed with the licensee, the procedures were changed to require system initiation via its associated logic circuit and to measure the time to reach rated flow and pressure. It should be noted that the licensee planned to perform a simulated automatic actuation (i.e., initiation via logic) and cold quick start tests of HPCI and RCIC at 1000 psig in accordance with the Power Ascension Test Program.

The inspector observed the performance of the 150 psig surveillance tests for both HPCI and RCIC. All tests were performed satisfactorily and the licensee declared both systems operable. The inspector had no further questions.

5.0 Surveillances

5.1 Radiological Environmental Technical Specifications

A 1988 licensee sponsored contractor audit of Technical Specification (TS) surveillance implementing procedures identified that the Radiological Environmental Technical Specifications (RETS) had not been incorporated into the licensee's Master Surveillance Tracking Program (MSTP), and in some cases adequate procedures had not been written. A review of RETS was initiated in response to the audit in October 1988. During this review the licensee identified that cumulative offsite dose contributions from radioactive effluents had not been calculated in accordance with the Offsite Dose Calculation Manual (ODCM) for the period of April through August, 1988 as required by TS. During this time only undocumented qualitative comparisions of current and past release data were made to determine if monthly doses were acceptable. The cause was determined to be an unfamiliarity with the requirements of the RETS by licensee personnel, and a lack of formal administrative controls for the scheduling and performance of RETS surveillance requirements. This licensee identified violation and the corrective actions implemented were described in inspection report 50-293/88-33, Section 3.b. Subsequently, the licensee identified two additional instances of failure to properly implement RETS. These two instances included:

(1) The licensee failed to perform the 1988 garden census out to the required three mile radius. The census was conducted to a radius of one mile. The TS requirement had previously been expanded from one to three miles by a license amendment. Weak review of the amendment resulted in the failure to implement the revision. Licensee follow-up identified one additional garden which should have been evaluated;

(2) The licensee failed to consider the contribution of gaseous tritium in completing monthly offsite dose calculations. The cause was determined to be weak communication between the Radiological Protection and Chemistry Departments. The licensee reviewed historical data and determined that the omission had no significant impact on the calculated doses, and that no TS limit had been exceeded.

In response to these problems the licensee elected to relocate the group responsible for environmental monitoring from the corporate engineering office to the site to provide for better communication with the balance of the organization. A dedicated project engineer was assigned, reporting to the Deputy Radiological Section Manager, to oversee review of the RETS and development of more formal administrative controls. The licensee has identified each RETS surveillance requirement as a line item in the MSTP. Procedures have been written to implement each requirement. The licensee's approach to resolution of this issue appears to be appropriately focused and timely.

The inspector noted that the above described licensee identified violations were determined not to be reportable under 10 CFR 50.73. Review of the licensee's basis for this determination indicates that the judgement was founded primarily on three premises:

(1) The events would be included in the 1988 Annual Radiological Environmental Monitoring Report;

(2) The failure to perform the TS surveillances did not result in occurrence of a condition prohibited by TS (i.e., no dose limit was exceeded);

(3) The surveillance requirement was solely administrative in nature. No Limiting Condition for Operation (LCO) is prescribed upon failure to perform the surveillance. No equipment was declared inoperable and therefore no LCO was exceeded.

The inspector questioned if the inclusion of the event in the annual report satisfies the reporting requirements of 10 CFR 50.73. Further, the inspector expressed concern regarding the stated basis for the reportability determination, and the underlying philosophy it suggests relative to the intent and application of RETS. The apparent intent of the RETS is to require licensees to closely monitor the performance of the waste treatment processes, and to take prompt action if these treatment processes are less than effective in reducing potential offsite exposure. This action may include repair of existing equipment, revision of operating practices to allow for more effective use of equipment, or evaluation of the benefit of potential hardware improvements. The RETS should be seen as the framework for a sound offsite exposure ALARA program. The position that the surveillance requirements are solely administrative in nature does not appear consistent with the purpose of RETS. The inspector discussed the above concern with the licensee's Radiological and Compliance Sections.

This item will remain unresolved pending NRC specialist inspector review of the technical adequacy of the licensee's newly generated RETS surveillance implementing procedures, and the adequacy of the licensee's approach to implementation of the RETS program in general (UNR 88-37-01).

The inspector also performed a brief review of the licensee's overall process for implementing TS revisions. The responsibility for ensuring that TS changes are appropriately reflected in surveillance, operating and maintenance procedures has not been clearly understood by licensee personnel in the past. Some confusion between the Modifications Management Group (MMG) and the Compliance Group existed regarding the division of responsibility. Recently however, the licensee has resolved this confusion by clearly assigning the task to the Compliance Group. Applicable program procedures are being written or revised. As described above, a contractor provided audit of all TS amendments through number 120 was performed in 1988. To ensure that additional amendments issued since completion of the audit have been properly dispositioned, the licensee is reviewing the intervening changes. Licensee actions in this area have been effective.

5.2 Routine Surveillance Tests

The inspectors observed the following surveillance tests:

8.M.1-1A	IRM Functional/Calibration;
8.M.2-3.3	SRM Functional;
8.M.1-4	APRM Flow Biased Signal Calibration;
8.M.1-13	Main Steam Line High Radiation Calibration;
8.M.2-2.5.6	HPCI Condensate Storage Tank Levels;
8.5.2.3	LPCI Motor Operated Valve Operability;
8.5.5.4	RCIC MOV Monthly/Quarterly Valve Operability Test;
8.7.1.5	Leak Rate Testing of Containment Isolation Valves;

It was determined that implementation of surveillance tests was generally well planned and controlled. On occasions, ineffective communications between control room operators and Instrument and Control (I&C) technicians caused confusion during surveillance tests. The licensee management agreed with the inspectors on the need to expand the "good communication practices" to other working groups (i.e. I&C) for formality and repeat backs. The inspectors will monitor this area in a future inspection.

6.0 Maintenance and Modifications

6.1 High Pressure Coolant Injection (HPCI) System Gland Seal Condenser Hotwell Pump Replacement

During HPCI testing at 140 psig steam pressure on January 10, 1989, the HPCI gland seal condenser level increased sufficiently to flood and overload the gland seal exhauster motor. Subsequent investigation disclosed degradation in the gland seal condenser hotwell pump (P-220). The impeller was worn and the casing eroded. The licensee installed a new pump under Plant Design Changes (PDC) 89-05 and 89-08. The inspector observed installation of the new pump, associated piping modifications, and post-work testing. It was noted that adequate ALARA planning, and health physics coverage were provided for the job. Pre-job briefings for the maintenance personnel at each shift were detailed and thorough.

In the past, the licensee had not predicated the HPCI system operability on the availability of the HPCI gland seal subsystem. However, the licensee changed that position based on results of a detailed review during this inspection. Licensee calculations to determine peak HPCI room temperatures show that should the HPCI system be operated without the gland sealing system functioning the room temperature could rise above 130°F. These calculations also assumed failure of one of the two room coolers. The equipment in the HPCI room is only qualified to a mild environment (approximately 100°F) and therefore could not be assumed to remain operable at the calculated elevated temperatures.

As a result of this analysis, the licensee has determined that the gland sealing subsystem must be operable prior to declaring the HPCI system operable. To monitor performance of the gland sealing system, the licensee has added appropriate portions of the system to the inservice testing (IST) program and modified the system to enhance testing. Baseline data has been taken and future testing has been scheduled. The inspector had no further questions and considered the licensee's evaluations to be thorough.

6.2 Intermediate Range Monitor (IRM) Detector Replacement

During the initial startup on December 30, 1988, "B", "D", and "G" IRM failed to respond to the neutron flux in the core. The licensee placed the reactor in cold shutdown and began investigation. Based on insulation resistance testing and voltage breakdown testing, it was determined to be detector failure. The licensee had replaced all eight IRM detectors during the last outage.

The licensee replaced the detectors with spares from the warehouse. The inspector reviewed the associated documentation, including:

-- The maintenance request package (MR 88-45-384);

-- Maintenance work plan;

-- Procedure 3.M.2-5,13, "IRM and SRM Detector Changeout";

-- Procedure 3.M.2-5.14, "SRM/IRM and TIP Detector Testing";

-- Procedure 8.M.1-1, "IRM Functional/Calibration check";

-- Procedure 3.M.2-5.6.11, "Checkout of SRM/IRM Retract Drive Components";

-- Pre-job briefing documentation;

-- Material balance area transfer form for special nuclear materials

The inspector determined that these documents were technically adequate and thorough. Post-work testing was performed per procedure 3.M.2-5.14 and 8.M.1-1. Vibration test of the retract drive components was also completed. It appeared that there was good oversight by health physics and quality control during the detector replacement.

The licensee is continuing with their root cause analysis on the detector failure. The inspector will continue to monitor licensee followup.

7.0 Review of Generic Letter 88-14

7.1 Secondary Containment Integrity

During evaluation of Generic Letter 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," the licensee determined that the reactor building trucklock door inflatable seals were supplied by the non-seismically qualified instrument air system. Since the instrument air system is not seismically qualified, it must be assumed to fail during a design basis seismic event. This condition is significant with respect to the reactor building inner trucklock door inflatable seal which constitutes a seismically designed secondary containment penetration. Therefore, the condition and performance of the inflatable seal following a seismic event directly impacts secondary containment integrity. In order to determine the impact of this scenario, on December 22, the licensee performed a secondary containment leak rate test with the inner trucklock door seal deflated and the outer door open. A negative pressure of only 0.18 inches of water was achieved using one train of the standby gas treatment system (SBGT). This failed to meet the required acceptance criteria of 0.25 inches of water.

The licensee subsequently designed and installed a passive mechanical interference seal system in accordance with Plant Design Change 88-53. On December 29, the secondary containment leak rate test was successfully conducted with the new door seal design in place and the inflatable seal deflated.

The licensee's response to an NRC initiative which lead to the identification of this issue, and the subsequent corrective actions taken to resolve the design deficiency were noteworthy. The inspector had no further questions.

7.2 Inadequate Reactor Building to Torus Vacuum Breaker Isolation Valve Design

Generic Letter 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," requested that licensees evaluate the effects of a loss of instrument air on the ability of safety-related components to perform their intended function. For example, during a seismic event, air operated safety-related components are assumed to fail due to a loss of the instrument air system. The licensee evaluated the susceptibility of various safety-related systems to this type of failure and found that the reactor building to torus vacuum breaker block valves would not provide their required containment isolation function if instrument air was lost.

After determining that the air supply for the accumulators for the reactor building to torus vacuum breaker block valves was not seismically qualified, the licensee initiated a controlled plant shutdown at 9:00 p.m., on January 10, 1989. Licensee senior management determined that it was prudent to shut down the plant until the vacuum breaker block valve design was completely evaluated. The inspector considered this decision to be conservative and evidence of a sound operational safety perspective. Cold shutdown was reached at 2:15 a.m., on January 11, 1989.

To prevent torus failure due to excessive external pressure, the reactor building to torus vacuum breaker block valves open to allow the in-series mechanical vacuum breaker to equalize the pressure between the torus atmosphere and the reactor building atmosphere. To isolate primary containment during the initial phase of a loss of coolant accident each of the two reactor building to torus vacuum breaker block valves closes to prevent leakage from the primary containment. These block valves (AO-5040 A&B) are held shut by air pressure and will fail-open on a loss of air pressure. Thus, a sufficient air supply is needed to ensure their containment isolation function. Individual safety-related accumulators (4 cubic feet) provide a small volume of air to each valve if instrument air becomes inoperable.

Testing performed after plant shutdown proved that this small volume was insufficient to cope with normal system leakage for the design basis mission time of 30 days. Minimum closing pressures were established individually for each valve. Licensee testing showed that minimum pressure to close valve AO-5040-A was 80 psig, and valve AO-5040-B was 62 psig. The difference in the minimum pressures was due to dissimilar valve operator orientation. Normal instrument air pressure is 108 to 113 psig. Hence, only a 28 psig drop in supply pressure would result in the inability to close the limiting valve. The licensee concluded that a air system modification was necessary to insure that the 30 day mission time was met.

Senior management believed the plant staff could complete their design review and install any needed modifications within 5 days of reaching cold shutdown. The plant staff responded quickly by developing a design change to install two 54 cubic foot low pressure accumulators each with its own high pressure makeup system, in series with the existing 4 cubic foot accumulators. Although the plant staff efforts were prompt, design options were not fully developed and many field changes were necessary to complete the modification.

The final design required operator action to make up for any losses from the low pressure system by adding air from newly installed, seismically supported, high pressure bottles. The high pressure portion of the system is located outside the reactor building and will be accessible during a post accident environment. While operator action to recharge the low pressure accumulators is acceptable, the design compromises associated in part with schedule constraints shortened the operator response time requirements from 30 days to the final design operator response time of 5 days. The inspectors reviewed the revised operator response time and concluded that the relatively simple actions to replenish the accumulator air system each five days would not result in any excessive operator burden in a post-accident situation.

The licensee completed the air system modifications and testing and commenced plant startup on January 27; the plant was critical at 2:12 p.m. Subsequently, in reviewing the air supply fill data for the accumulators, the licensee noted increased air system leakage. The licensee determined that the increase in leakage had occurred when the low pressure accumulators were recharged after leak rate testing was complete.

The recharging evolution brought system pressure to 125 psig which was only 5 psi below the system relief valve setpoint of 130 psig. While there is no evidence that the relief valves lifted they both showed seat leakage when subsequently tested. This new leakage path doubled the total system leakage from the leakage rate previously determined and raised the leakage rate above the licensee's own conservatively established limit for system operability. The reactor building to torus vacuum breaker block valves were declared inoperable and a plant shutdown was commenced at 9:55 p.m. At 10:10 p.m., on January 27, the licensee declared an Unusual Event (UE) due to the initiation of a plant shutdown required by Technical Specifications. The reactor was brought subcritical at 10:15 p.m. on January 27, and the UE was terminated at that time. Had plant staff taken the time to fully develop the modification, to perform more comprehensive testing, to thoroughly evaluate system operating margins, and to fully develop associated administrative controls, the plant shutdown due to excessive air system leakage might have been prevented.

The licensee considered the excessive leakage to be due to the relief valves on the two accumulators lifting and reseating at erratic pressures. The inspector observed the torus to reactor building vacuum breaker block valve leak tightness testing on January 30. The system was filled and checked for leakage at various fittings and mechanical joints by using a Helium detector. No appreciable leakage at these points was found.

At several points during the redesign effort the licensee revised the leakage acceptance criteria and operator response frequency for the accumulators. In addition, the licensee is evaluating the possibility of relocating the relief valves outside the normal system boundary. Licensee efforts were ongoing and the inspector will continue to monitor licensee activities during the next inspection period.

7.3 Conclusions

The licensee's review in response to NRC Generic Letter 88-14 was thorough and well conceived. In conducting their evaluation the licensee identified the two design deficiencies documented above and took prompt conservative action to address both items.

The design change which corrected the secondary containment truck lock deficiency was implemented in a timely manner and was well thought out from conception to implementation.

In the case of the torus vacuum breaker block valve modification the licensee's decision to modify the system was conservative and showed excellent safety perspective. It must be noted that the licensee's initial attempt at implementation of the design change did not go smoothly, over fifty field revision notices were needed to complete the modification. The inspector attributes these difficulties to overly aggressive goal in completion schedule set by upper management, and weak vertical communications.

Efforts to design the system, procure components, construct and test the system were all affected by schedule demands. Although the initial design met all code and license requirements, operating characteristcs and acceptance criteria were extremely restrictive and led directly to the shutdown and declaration of an UE on January 27, 1989.

The role that the Onsite Review Committee (ORC) took throughout the modification process met the requirements of Technical Specifications. ORC reviews of the design change were deliberate and thorough. Members of ORC recognized the operating constraints of the modification, however, weak organizational communications prevented upper management from recognizing the consequences of those constraints.

The licensee held a management critique of the vacuum breaker modification process in an attempt to identify root causes that led to the system failure. Licensee management concluded that no single root cause resulted in the UE but that multiple technical design weaknesses led to the system leakage and inoperability. Licensee management also reached the conclusion that the common factor in all the technical causal factors is that they were the result of aggressive demands on schedule. The licensee was extremely frank and self critical throughout their self assessment process and the inspector has concluded that the assessment was very good. Licensee management performance in the assessment was well focused and came to a well balanced conclusion.

8.0 Radiological Controls

Radiological controls were observed by the inspectors on a continuing basis throughout the reporting period. In addition, a health physics specialist also reviewed portions of the licensee's radiological protection program during this inspection period.

8.1 Radiation Monitoring Systems

The inspector reviewed the calibration and operability status of the area radiation monitors (ARM) and selected ventilation system radiation monitors through tours of the plant, review of records and interviews with calibration personnel and systems engineers. All fifteen channels of ARM were found to be in calibration and functional. The next six month calibration will occur in March 1989. There are no repairs or improvements planned on the system prior to power operations. Procedure No. 6.5-160, "Calibration of the Area Radiation Monitoring System," appears to be adequate. Calibration dates are included in the Master Surveillance Tracking Plan (MSTP) computerized work schedule.

The licensee had installed special "high radiation area monitors" in the traversing incore probe (TIP) room and several radwaste locations. These were declared not functional several years ago when spare parts became unavailable. The licensee was requested by the inspector to evaluate whether these monitors are needed and to evaluate the personnel exposure to effect repairs. The inspector noted that these monitors are not required by the Technical Specifications. The inspector will review this item during a future inspection.

8.2 Special Radiation Surveys

Because of the extended shutdown and extensive equipment and plant modifications made during the outage, special radiation surveys will be conducted during plant startup and initial operations to detect shielding changes. Airborne radioactivity is continuously monitored by Beta Aerosol Beacons (BAB) placed in certain plant areas. When reactor steam is fed to an area for the first time there are several grab samples taken of airborne particulate and gaseous activity to detect steam leaks from the equipment. Special gamma and neutron dose rate surveys are conducted also to detect shielding changes. These are repeated as the power level and general area dose rates increase. Implementation of these special surveys is accomplished through "standing orders" issued to the health physics (HP) technicians. HP supervisors continue to review survey results. The inspector concluded that the approach was adequate.

8.3 Control of Locked High Radiation Areas

The inspector reviewed the licensee's control of locked nigh radiation areas (i.e., greater than 1000 mrem/hr general area). The inspector reviewed the licensee program to ensure proper control of radiation areas during the power ascension program. Because the plant has been in an extended outage status, many of the radiological conditions associated with power operations have not been encountered in excess of 30 months. In order to ensure readiness to survey, post and control access to high radiation areas resulting from normal power operations, equipment malfunctions and maintenance activities, the licensee developed a comprehensive high radiation area control plan for the power ascension program. Initially, Radiological Operations Division personnel retraining was provided to emphasize the responsibilities and regulatory requirements associated with the control of radiation areas. A historical review of past operational cycles was performed by the licensee to identify plant locations that required high radiation area postings and to review reactive maintenance activities in which special radiological protective actions were invoked. The licensee also contacted other similar BWR facilities to gain and exchange operational experience and industry initiatives in the radiological protection area. Additionally, responses to past Notices of Violation and NRC concerns regarding radiation area controls were reviewed to ensure corrective actions had been properly incorporated.

In conclusion, the inspector determined via plant walkdowns of existing posted radiation areas, review of the power ascension high radiation area control plan, and interviews with Radiological Section personnel, that proper professional attitudes and programmatic controls are present to provide positive access control to high radiation areas during power ascension.

The control of locked high radiation areas is generally adequate. However, a locked high radiation area door to the radwaste building truck lock (RBTL) was found unlatched during a licensee's shiftly surveillance on February 3, 1989. The door, one of three personnel access paths to the RBTL, was not normally used. Radiation surveys performed by the licensee showed a general area radiation level of 250 mrem/hr; the highest radiation level of 1200 mrem/hr was at the top of a sludge liner. The pocket optical dosimeter readings of all personnel logged into the process buildings from the time the RBTL became a locked high radiation area on January 31, 1989, until the door was relocked on February 2, 1989, were checked by the licensee and no substantial exposure was noted.

The inspector noted that the licensee's response was prompt and their investigation was thorough. The identified root cause was personnel error by technicians who checked only the door used, rather than all doors, each time work ceased in the RBTL. The following proposed corrective actions were either taken or will be taken by the licensee:

- The technicians who did not check all doors upon exiting the RBTL were counselled;

- Discussion of this occurrence and the need for greater sensitivity to locked high radiation area controls was conducted with all radiological technicians on site;

- Checking of all doors to a locked high radiation area upon exiting the room will be explicitly incorporated into station procedure 6.1-012, "Access to High Radiation Areas;"

- The need for greater sensitivity to high radiation area controls will be incorporated into initial and requalification General Employee Training.

Inadequate control of locked high radiation areas had been an area of previous NRC concern. Notices of Violation had been issued in the past during inspections 50-293/87-03, 50-293/87-11, 50-293/87-19 and 50-293/87-57 which addressed these concerns. In regard to these violations, the licensee instituted extensive corrective actions which have been successful. The Integrated Assessment Team Inspection conducted in August 1988 determined that the licensee's program in this area, including the shiftly surveillances on locked high radiation area doors was effective.

Based on the above, the failure to comply with the requirements of Technical Specification 6.11 and implementing procedure 6.1-012 is considered a licensee-identified violation. Consequently, no Notice of Violation will be issued (88-37-02). The inspectors will routinely monitor this area during the power ascension program.

9.0 Followup on Previous Inspection Findings

(Closed) Unresolved Item 88-31-01, Discrepancies in Control Room High Efficiency Air Filtration (CRHEAF) System Procedures. During inspection 50-293/88-31, five discrepancies in the CRHEAF system operating and surveillance procedures were identified. The licensee's System Engineering Group subsequently reviewed the concerns and processed appropriate procedure revisions. During this report period the inspector evaluated licensee corrective actions, including the procedure changes and supporting engineering calculations. Following is a summary of licensee actions in response to each of the five items:

(1) The CRHEAF system operating and test procedures did not incorporate position verification and securing of system manual dampers. The licensee revised procedure 8.7.2.7, "Measure Flow and Pressure Drop Across Control Room High Efficiency Air Filtration System," to adjust system manual dampers and to apply HVAC balance stickers to assure proper positioning is maintained.

(2) Technical Specification 4.7.B.2.c requires that the CRHEAF system inlet heaters be capable of an output of at least 14 KW. Procedure 8.7.2.8, "Perform a Functional Test of Humidity Controls and Inlet Heater Capabilities of the Control Room Air Filtration System," did not require that this output value be met. The licensee has revised the procedure to require that measured output exceed 14 KW.

(3) Adequate acceptance criteria were not established in Procedure 8.7.2.8 for the single heater element in each train which is controlled by the humidistat. Existing acceptance criteria required a minimum output of 3.8 KW. This value however, was calculated using data obtained at the normal bus voltage of 490 to 500 VAC, without adjustment to account for potential degraded voltage conditions.

In response to the inspector's concern, the licensee collected data using a clamp-on ammeter, calculated the heater output, and adjusted the output to account for potential degraded voltage conditions. Results of this initial testing indicated that the heater could not fulfill its intended function. On November 18, 1988, the licensee declared the system inoperable and notified the NRC via ENS of the deficiency. The licensee implemented a Temporary Modification (TM) connecting a second heater element to the humidistat controlled circuit, along with the original element, increasing the KW output to an acceptable level.

Subsequently, the licensee revised the test method to include use of in-line ammeters. In addition, engineering calculations were performed which support establishment of higher expected voltages during degraded voltage conditions. The combination of a more accurate test method, and revision of the acceptance criteria to account for the new expected minimum voltage indicates that the original single heater element is capable of satisfying the design function. The licensee plans to remove the TM and return the system to normal.

(4) Procedure 7.1.30, "HEPA Filter and Charcoal Performance Test Program," did not contain any quantitative acceptance criteria. The licensee has revised the procedure to include appropriate acceptance criteria.

(5) Procedure 8.E.47.1, "Control Room/Radwaste Filtration System Instrumentation Calibration/Logic Functional Test," requires that low flow be simulated to effect a standby train auto start. No method of simulating the low flow was specified. Technicians indicated that it would be simulated by lowering the setpoint or disconnecting the

instrument tubing. The inspector questioned the impact of this practice on instrument calibration. The licensee verified that the setpoint had not been manipulated since the last instrument calibration. The procedure is currently undergoing a major revision which will be completed before its next implementation. The licensee stated that as part of this revision the procedure will be changed to specify that the low flow signal and resultant standby train auto-start will be generated by securing the operating fan.

Corrective actions implemented by the licensee in response to the above items are adequate. The inspector had no further questions regarding these procedure revisions.

During the course of the licensee's review in response to item number 3 above, it was noted that the Technical Specifications require only that the total heater output of 14 KW be verified. Only one of the four elements is controlled by the humidistat and functions to reduce inlet air relative humidity to an acceptable level. The remaining three elements serve only for comfort control. It appears that the TS should include an output KW value for the single required heater element to ensure that it has not degraded. Technical Specifications require periodic measurement of system flow and pressure but do not require verification that the system is capable of performing its basic design function, maintaining positive control room pressure. In both these instances the licensee has performed adequate testing to demonstrate that the design functions are maintained. The inspector however, expressed concern to licensee management that if TS are not adequate or accurate they should be appropriately revised. The licensee acknowledged this observation.

10.0 Review of NRC Temporary Instructions

10.1 Verification of Quality Assurance - Diesel Generator Fuel Oil (TI 2515/93)

The objective of this inspection was to assure that diesel generator (DG) oil is included in the BECo Quality Assurance Program under 10 CFR Part 50, Appendix B requirements. Consumable items whose quality is necessary for functional performance of safety-related components, such as DG fuel oil, are classified as safety-related and are subject to the applicable provisions of 10 CFR Part 50, Appendix B. The Pilgrim Nuclear Power Station Q-list, Revision 17, identifies those items that are safety-related. The Q-list includes System Number 61, "Diesel Generators and Auxiliary Systems," and identifies fuel and lubricating oil as being included as part of the "Q" list.

Licensee Quality Control Instruction 7.07 requires that the commercial quality item evaluation (CQI) and Material Procurement and Receiving Instruction (MPRI) number 52 be used to assure the quality of the DG fuel oil. The CQI and MPRI No. 52 specify that the fuel oil conform to the specifications in American Society for Testing and Materials (ASTM) D975-81, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products." This is consistant with the DG fuel oil surveillance requirements of Technical Specifications 4.9.A.1.e and 4.12.B.1.i for the safety-related DG's, and the diesel driven fire pumps. Based on the above, the inspector determined that adequate measures are being taken to assure the quality of DG fuel oil, as specified in the Technical Specifications. This inspection closes TI 2515/93.

10.2 Verification of BWR Recirculation Pump Trip (TI 2515/95)

The objective of this inspection was to verify the installation of the recirculation pump trip (RPT) function for low reactor vessel water level or high reactor vessel pressure. The purpose of the RPT is to significantly limit the consequences of an anticipated transient without scram (ATWS) event. A trip of the recirculation pumps on either of the parameters identified above causes an increase in the moderator voids in the reactor core; therefore, power and pressure surges which might occur during an ATWS event are substantially reduced due to the negative reactivity resulting from the RPT.

Walkdown of the ATWS modifications to the RPT, including inspection of 'B' recirculation pump MG set field breaker was completed and documented in inspection report 50-293/86-24.

The NRC staff approved the licensee's proposed RPT including a change to the Technical Specifications, by letter dated May 12, 1980. This letter included Amendment No. 42 to the Technical Specification and the supporting safety evaluation (SE). The SE approved tripping the recirculating pumps on high reactor vessel pressure or low-low water level.

The inspector reviewed Plant Design Change Request (PDCR) 79-25, "ATWS Reactor Recirculation Pump Trip System." The PDCR included a closeout memo dated January 11, 1984, which included a list of all applicable as-built drawings. Based on the previous system walkdown, issuance of revised Technical Specifications and the closeout memo, the inspector determined that the recirculation pump trip has been properly installed and is operable. This inspection closes TI 2515/95.

10.3 Verification of Mark I Containment Wetwell/Drywell Vacuum Breaker Modifications (TI 2515/96)

The object of this inspection was to verify that modifications to the Pilgrim Mark I (MKI) containment vacuum breakers in response to Generic Letter (GL) 83-08 had been completed and used the correct materials. The GL requested licensees to perform plant specific analysis to determine the adequacy of the MKI containment vacuum breakers to withstand chugging and condensation oscillation loads which would result during a loss of coolant accident (LOCA).

The licensee's response to GL 83-08 proposed modifications to the Pilgrim Mark I containment vacuum breakers. The modifications included changes and new materials for the vacuum breaker pallets, hinge shafts, arms and hinge arm studs. The NRC staff approved the proposed modifications in a safety evaluation issued by letter dated January 15, 1987.

The inspector reviewed Plant Design Change (PDC) 83-19G, Rev. 0, "Torus Vacuum Breakers Upgrade." The inspector reviewed the purchase order for the material used in the modifications and determined that the materials were consistent with that specified in the licensee's proposed modification package submitted to the NRC. Based on the above findings, the inspector has determined the modifications were completed and the proper materials were used. This inspection closes TI 2515/96.

11.0 Review of Licensee Self Assessment Activities

The inspectors routinely monitored the licensee's inplace programs to assess facility and personnel performance. The licensee has implemented a formal peer evaluation program of routine personnel performance monitoring. The individuals selected for the peer evaluator program are selected from the onsite organization, receive training on performance monitoring techniques and are assigned to monitor specific activities. The peer evaluator program provided twenty-four hour operations monitoring during all periods when the facility was critical, as well as routine audits of other areas of facility activities. The peer evaluators held regular debriefings with audited organizations to discuss identified strengths and weaknesses. NRC inspectors who attended these debriefing sessions observed that the findings, both positive and negative were discussed in a frank, open atmosphere. The audited organizations have generally been receptive to this process and the training, resolution and closeout of findings has been timely and thorough.

The inspector also noted greatly increased presence of management in the plant throughout this period. Routine presence of middle and senior level management in the control room and in the plant was noted. Management oversignt and control of routine and abnormal activities showed clearly that the licensee has set high performance standards.

The licensee's quality assurance organization has also developed a special audit program for the duration of the power ascension plan. The inspectors noted an increased presence of quality assurance and quality control personnel throughout the inspection period.

Management efforts in assuring high standards of facility and personnel performance were evident throughout this inspection period. The licensee was highly self-critical in this self assessment period and overall management performance was good.

12.0 Management Meetings

At periodic intervals during the course of the inspection period, as well as after the close of the inspection, meetings were held with senior facility management to discuss the inspection scope and preliminary findings of the resident inspectors. No written material was given to the licensee that was not previously available to the public.

ATTACHMENT I

Persons Contacted

R. Bird, Senior Vice President - Nuclear

* K. Highfill, Site Director

R. Anderson, Plant Manager

D. Eng, Outage and Planning Manager

E. Kraft, Training Department Manager

D. Swanson, Nuclear Engineering Department Manager

D. Long, Plant Support Department Manager

J. Alexander, Operations Section Manager

J. Jens, Radiological Section Manager

J. Serry, Technical Section Manager

R. Sherry, Maintenance Section Manager

L. Olivier, Chief Operating Engineer

J. Neal, Security Division Manager

W. Clancy, Systems Engineering Division Manager

F. Wozniak, Fire Protection Division Manager

ATTACHMENT II

Facility Tour Findings by Regional Administrator - December 29, 1988

-- Hose connections on the scram discharge instrument volume (SDIV) drain lines were unconnected at the other end;

The licensee removed the hose and capped the drain lines.

-- Valve HO 301-1000 on SDIV appeared partially open;

The licensee verified the valve was closed.

-- A sight glass was on the SDIV and it appeared that the tank was vented to the area through the sight glass;

The sight glass had been isolated.

-- Valve lineup on the SDIV was last performed in February 1988;

The resident inspector independently checked a valve lineup on December 30, 1988, and noted no discrepancies.

-- Indication of small leak on threaded fitting into RCIC pump bearing oil reservoir was noted;

The licensee submitted Maintenance Request 88-13-90.

-- A pressure gage on HPCI suction piping was broken;

The licensee completed Maintenance Request 88-23-133.

-- Limit switches on nitrogen purge valves on HPCI were not connected;

Indication from these valves are not used.

-- Scaffolding materials, i.e., nails and wood chips, laying on floors which could migrate to drain systems and cause pump or valve damage;

A walkdown was performed covering all staging and scaffolds. Nails and wood chips were removed.