U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.:	50-293
Report No.:	93-14
Licensee:	Boston Edison Company 800 Boylston Street Boston, Massachusetts 02199
Facility:	Pilgrim Nuclear Power Station
Location:	Plymouth, Massachusetts
Dates:	July 13 - August 16, 1993
Inspectors:	J. Macdonald, Senior Resident Inspector A. Cerne, Resident Inspector D. Kern, Resident Inspector

Approved by: Brenda J. Whitaker for E. Kelly, Chief, Reactor Projects Section 3A, DRP — 9/8/93 Date

Scope: Resident safety inspections in the areas of plant operations, maintenance and surveillance, engineering, and plant support. Initiatives selected for inspection included the implementation of training and design modifications associated with NRC Bulletin 93-03.

Inspections were performed on backshifts during July 13-15, 19-22, 26-30 and August 2, 3, 5, and 9-13. Deep backshift inspections were performed on July 24 (9:00 a.m. - 1:00 p.m., and 8:00 p.m. - 12:00 midnight), July 25 (8:05 a.m. - 12:45 p.m.), August 1 (5:05 - 10:30 p.m.), and August 10 (10:00 - 10:20 p.m.).

Findings: Performance during this five week period is summarized in the Executive Summary. The lack of a one hour report to the NRC consistent with 10 CFR 50.72 criteria following the July 22 identification of pressure boundary leakage is unresolved pending review of the associated Licensee Event Report (50-293/93-14-01).

EXECUTIVE SUMMARY

Pilgrim Inspection Report 93-14

Plant Operations: The July 22, reactor shutdown to identify the source of increased unidentified drywell leakage was well controlled. Prior to the shutdown, a conservative administrative leakage limit had been established. Notwithstanding good safety parameter controls during the July 22, 1993 shutdown, a one hour non emergency notification to the NRC following identification of pressure boundary leakage which would require a reactor shutdown was not accomplished. The lack of formal notification was of minimal significance and will remain unresolved pending inspector review of the associated Licensee Event Report.

For a brief period following reactor restart on July 26, 1993, one train of the anticipated transient without scram (ATWS) system was inoperable due to procedural weaknesses which allowed two ATWS pressure transmitters to remain isolated. Immediate actions by operations personnel to restore the affected ATWS train to an operable condition were appropriate. Follow-up corrective actions to preclude recurrence were effective.

Maintenance and Surveillance: A pressure boundary weld repair for non-isolable reactor vessel drain line leakage path was thoroughly planned and well executed. Work package planning, in situ communications, and the application of a freeze seal isolation technique effectively established a system configuration.

Plant Support: Radiological practices continued to be of high quality during this period, particularly the radiological support provided during repair of the reactor vessel drain line socket weld.

Engineering: Procedure revisions and plant design changes were implemented to improve the reliability of reactor vessel level instrumentation indication and to provide control room operators with enhanced level monitoring capability. The engineering analysis, construction, post installation testing, and subsequent operator training associated with those modifications were comprehensive. An extensive post modification test program verified that reactor vessel level instrumentation responded as designed during and after reactor startup with the reference leg backfill system in service.

TABLE OF CONTENTS

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

At the start of the report period Pilgrim Nuclear Power Station was operating at approximately 100% of rated power. Unidentified drywell leakage increased from 2.5 gallons per minute (gpm) at the beginning of the report period to 3.01 gpm on July 21. The Technical Specification limit for unidentified drywell leakage is 5.0 gpm.

On July 19, the high pressure coolant injection (HPCI) system was declared inoperable due to a discharge piping high pressure annunciator failure during a routine surveillance. The annunciator was repaired and HPCI was returned to service on July 20.

On July 22, the licensee conducted a reactor shutdown to identify the source of the increasing drywell unidentified leakage and to complete the necessary corrective repairs. The shutdown and corrective repairs are discussed in Sections 2.2 and 3.1. While the plant was in cold shutdown, a reference leg backfill hardware modification was installed to improve the reliability of reactor vessel level indication as requested by NRC Bulletin 93-03.

The reactor was restarted on July 25 and the turbine generator was synchronized to the off-site distribution system on July 26. On July 27, the reactor achieved full rated power. Throughout the report period, the licensee continued to investigate instability of the recirculation pump speed controllers. Preliminary troubleshooting indicated the most likely cause to be age-related failure of electrolytic capacitors in the speed limiter control circuit. The 'A' recirculation pump speed was manually locked at a fixed value by placing the speed control scoop tube in the lockout position pending the completion of troubleshooting and corrective actions.

2.0 PLANT OPERATIONS (71707, 40500, 90712)

2.1 Plant Operations Review

The inspector observed the safe conduct of plant operations (during regular and backshift hours) in the following areas:

Control Room	Fence Line (Protected Area)
Reactor Building	Turbine Building
Diesel Generator Building	Screen House
Switchgear Rooms	
Security Facilities	

Control room instruments were independently observed by NRC inspectors and found to be in correlation amongst channels, properly functioning and in conformance with Technical Specifications. Alarms received in the control room were reviewed and discussed with the operators; operators were found cognizant of control board and plant conditions. Control room and shift manning were in accordance with Technical Specification requirements. Posting and control of radiation contamination, and high radiation areas were appropriate. Workers complied with radiation work permits and appropriately used required personnel monitoring devices.

Plant housekeeping, including the control of flammable and other hazardous materials, was observed. During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication of equipment status. These records included various operating logs, turnover sheets, tagout, and lifted lead and jumper logs.

2.2 **Reactor Shutdown Due to Unidentified Leakage**

On July 22, 1993, at approximately 12:01 a.m., with the reactor at 100% reactor power, the licensee initiated an orderly reactor shutdown to address an increased unidentified drywell leakage condition. Unidentified leakage had slowly and consistently trended upward since the most recent reactor startup that occurred on June 3, 1993. At 4:00 p.m., on July 21, the unidentified leakage rate was calculated to be 3.01 gpm. The technical specification limit is 5.0 gpm. Chemistry analysis of the drywell floor sumps indicated that the leakage was reactor coolant quality water. The licensee initially suspected the leakage to be from a jacking bolt hole outside of the pressure boundary on the B recirculation pump, which had a history of leakage. Technical Specification 3.6.C.1.a requires that the operational reactor coolant system leakage be limited to 1) no pressure boundary leakage, 2) unidentified leakage of less than or equal to 5 gallons per minute (gpm), 3) total leakage to be less than or equal to 25 gpm averaged over any 24 hour period, and 4) an increase of less than or equal to 2 gpm in unidentified leakage within any 24 hour period. Technical Specifications require when any pressure boundary leakage is detected that the reactor be in hot shutdown within the next 12 hours and be in cold shutdown within the next 24 hours. For unidentified or total leakage limits, technical specifications allow 4 hours to identify and/or reduce the leakage to allowable limits prior to requiring a shutdown consistent with the periodicities above.

Shortly after 5:00 a.m., on July 22, the reactor mode select switch was placed in the STARTUP position with the reactor at approximately 5% of rated power. The reactor was subcritical at 9:15 a.m., and all control rods were fully inserted by 12:09 p.m. Operations personnel initiated a preliminary drywell inspection at approximately 8:00 a.m. The drywell entry was controlled via radiation work permit no. 93-2397. A minor leak was identified at the upstream socket weld to the reactor vessel drain line hand operated isolation valve, HO-261-65. At 9:30 a.m., Problem Report 93.9335 was issued to document the drain line leak. Repair of the valve is documented in Section 3.1 of this report.

The leakage at the reactor vessel drain line weld location was a non-isolable fault in a reactor coolant system component body to pipe wall interface and as such was classified as pressure boundary leakage. As stated previously, technical specifications require that reactor coolant system leakage be limited to no pressure boundary leakage and that if a pressure boundary leak is identified, maneuver the reactor to hot shutdown within the next 12 hours and be in cold shutdown within the next 24 hours. Ultimately the reactor entered cold shutdown conditions at 7:40 p.m., approximately 11 hours after discovery of the pressure boundary leakage and well within the 24 hours required by technical specifications.

The inspectors observed various portions of the shutdown and concluded the evolution was well controlled and safety parameters such as reactor vessel temperatures and pressure were maintained at all times. Additionally, the licensee took prompt actions to conduct a drywell inspection with the reactor at pressure to improve the potential to identify the origin of the leakage. However, the inspector expressed concern that, at the time the licensee identified the leak as pressure boundary leakage, the station entered the technical specification action statement that required a reactor shutdown. This situation was a technicality in that the reactor was being brought to a cold shutdown condition, and the required actions were therefore already being fulfilled. Notwithstanding the fact that reactor power had been already decreased to below 5% prior to identification of the pressure boundary leakage, the inspector concluded that formal notification to the NRC had been required. Specifically, a one hour notification in accordance with 10 CFR 50.72(b), Criterion (i)(a) is required for the initiation of any nuclear plant shutdown required by the plant's Technical Specifications. This position was discussed with the licensee. Following evaluation, the licensee concurred with the inspector determination and stated the intention to include discussion of the lack of initial one hour event notification to the NRC in the 10 CFR 50.73 required Licensee Event Report (LER). This issue is identified as an unresolved item pending resolution of questions regarding details and corrective actions contained in the associated LER 93-18 which was issued just after the close of this inspection period (50-293/93-14-01).

2.3 Primary Containment Isolation System (PCIS) Group 3 Actuation

During the July 22, 1993, reactor shutdown, while placing the residual heat removal (RHR) system in service to enter the shutdown cooling (SDC) mode of operation, the SDC suction piping isolation valves automatically closed upon receiving a PCIS Group 3 isolation signal. As the SDC suction isolation valves were closing, the running RHR pump automatically tripped as designed. However, no alarm annunciated in the control room to indicate the cause of the initiating Group 3 isolation. Within minutes, the operators reset the PCIS circuitry and placed the RHR system into SDC service.

While the isolation was not spurious (i.e., an actual isolation signal setpoint was reached), the transient nature of the initiating conditions were most likely attributable to a momentary pressure spike caused by opening of the RHR "A" loop injection valve. This pressure transient was sensed through the idle "A" recirculation loop piping by the pressure switches monitoring reactor pressure. A brief pressure spike, above the 100 psig setpoint to protect the RHR system piping, was of sufficient duration to deenergize the relays that actuate the isolation without electrically closing the contacts that provide the SDC high reactor pressure alarms. Hence, the expected control room panel 903L alarms were not annunciated at the time of this Group 3 isolation.

The inspector discussed this event with operations personnel and reviewed both problem report 93.9334 and control room log entries to confirm the sequence of operator activities to establish SDC, consistent with PNPS procedure 2.2.19. This RHR procedure has detailed filling and venting requirements prior to the initiation of SDC operation. The inspector had discussed with NRC personnel from the NRR Events Assessment Branch, similar isolation events that had occurred at other plants, which had been caused by the formation and collapse of voids in the RHR system created by improper filling and venting preparations. The procedural controls at the PNPS appear to adequately address trapped air and steam voids and have been successfully used in the past to initiate SDC; thereby pointing to the pressure wave created by opening of the injection valve as the likely cause of the isolation pressure switch actuation.

The licensee performed functional and calibration tests of the pressure switches and checked the 903L annunciators for high reactor pressure and verified the proper operation of these instruments. Design change options to prevent such pressure transients of short duration from causing unnecessary Group 3 isolations are being evaluated by licensee engineering personnel. The inspector confirmed that the licensee considers this event reportable in accordance with the requirements of 10 CFR 50.73 and that a Licensee Event Report would be prepared and transmitted to the NRC.

The inspector determined that the interruption in the establishment of SDC had little safety impact in that the main steam isolation valves remained open to the condenser heat sink until such time as the RHR system was successfully placed in service in the SDC mode. The inspector concluded that the PCIS Group 3 isolation, while not spurious, did not occur as a result of an intended protective action. The inspector has no additional questions at this time and intends to conduct any further review of this event which is necessary after the submittal of the BECo Licensee Event Report.

2.4 Operational Followup

The inspector checked equipment status, work controls, and operational impact and interviewed cognizant licensee personnel in the followup of specific component and material problems, identified below:

- On July 16, 1993, the licensee conducted repair activities in accordance with maintenance request MR 19302774 to the auxiliary bay watertight door separating the two trains of reactor building closed cooling water (RBCCW) system components. A BECo Nuclear Engineering Division (NED) evaluation indicated that the door was not required for flooding protection. This evaluation, which addressed the FSAR discussion of this door as a watertight barrier, was posted in the Operations Night Orders for review by the operators on watch. Based upon previous NRC inspection regarding the safety-related function of the auxiliary bay water tight door (reference: Inspection Report 92-03), the inspector questioned the status of plans to update the FSAR to eliminate the credit attributed to the door in maintaining RBCCW loop redundancy. While the NED analysis determined that the FSAR did not require revision, the licensee subsequently concluded that an FSAR change to eliminate confusion was prudent and FSAR change request 1931 was submitted and scheduled to be incorporated in the next FSAR update scheduled for 1994.

Furthermore, in conjunction with inspector observations of control room activities and tours of the plant conducted during this inspection period, the inspector noted that a light on the control panel, indicating that the auxiliary bay watertight door is open, appeared to be illuminated more than a reasonable amount of time assumed for personnel entries into the areas. Discussion with licensee personnel led to increased monitoring by the operations staff and subsequent repositioning of the limit switch on the door to correct a false door status illumination problem that was identified. The inspector noted that, consistent with the nonsafety door function, the control room status light provided indication only and required no operator response. The inspector considers the licensee actions in effecting repairs to the limit switch and a revision to the FSAR, as described above, to be appropriate corrective measures to the identified discrepancies.

- A limiting condition for operation (LCO A93-123) for high pressure coolant injection (HPCI) system inoperability was entered on July 19, 1993, to evaluate and repair the failure of a low pressure alarm for the HPCI pump discharge header identified during the conduct of surveillance procedure 8.M.2-2.7. A problem report, PR 93.9331, was written relative to this pressure switch (PS-9090) problem. The inspector confirmed through a review of piping and instrumentation drawing M243 that PS-9090 only serves an alarm function and thus, that the HPCI system remained available to perform its safety function, even though it was declared inoperable in accordance with Technical Specification 4.5.H.4. Discussion with operations personnel indicated that the cause of the alarm (E-3 on control panel C904) failure was a missing jumper wire in the C904 circuitry that related to control panel modifications implemented during the refueling outage completed in May 1993. The inspector verified that the licensee re-checked other modifications of control wiring which had been installed to evaluate the potential for similar jumper problems. None were identified. The PS-9090 alarm wiring problem was corrected and the HPCI system restored to operable status on July 20, 1993.

- On July 26, 1993, a new supply of fuel oil for the emergency diesel generators (EDG) was delivered to PNPS and sample tested in accordance with station procedure 7.1.55. The shipment passed the acceptance criteria of the PNPS site tests and was discharged into the EDG fuel storage tanks. As required, new fuel samples were transmitted to a vendor for additional laboratory testing. On August 5, 1993, the qualified vendor laboratory analysis report of this diesel fuel shipment arrived at the site and indicated a fuel flash point, 108 degrees F, in nonconformance with the specified procedural minimum requirement of 125 degrees. The licensee issued nonconformance report NCR 93-136 and problem report 93.9352 and conducted additional flashpoint testing of each EDG fuel bulk storage tank with acceptable results (i.e., "A" tank = 148 degrees F, "B" tank = 144 degrees F).

The inspector reviewed NRC 92-136 and PR 93.9352. PNPS Technical Specification 4.9.A.1.e requires EDG fuel to be in compliance with the acceptable limits of ASTM standard D975-81. The inspector examined the detailed requirements for diesel fuel oils specified in Table 1 of ASTM D975 and noted that the flash point is not considered to be a quality parameter of the diesel fuel that directly affects EDG performance. This was recognized by NED in the NCR review which noted that flash point testing is primarily a fire protection requirement. Therefore, it was concluded that operability and/or Technical Specification compliance were not an issue. NCR 92-136 was subsequently dispositioned to "accept-as-is" the material nonconformance. However, PR 93.9352 remains open for further licensee evaluation of the question whether the addition of new fuel deliveries to the EDG storage tanks is a prudent practice prior to the receipt of all acceptable test results. The inspector reviewed PNPS procedure 7.1.55 and considers the licensee followup to PR 93.9352 to be a reasonable approach to address the generic and specific procedural applicability issues identified with respect to this problem.

The inspector assessed the licensee's response to the issues identified above, and determined that appropriate safety perspectives had been applied to problem resolution. Licensee documentation, evaluation and assignment of resources to corrective action were appropriate and commensurate with the safety significance. With the exception of the delay of the FSAR update for the auxiliary bay water-tight door questions identified in 1992, the licensee corrective measures were timely.

2.5 Single Train of Anticipated Transient Without Scram System Inoperable

While performing post modification testing of a reactor vessel (RV) level hardware design change (see Section 4.1), plant personnel found RV pressure transmitters PT-263-122A and PT-263-122C isolated. This caused a single train of the Anticipated Transient Without Scram (ATWS) system to be inoperable. Technical Specifications permit continued reactor operation in the 'RUN' mode for up to fourteen days with one ATWS train inoperable, provided that the other train of ATWS is operable. Operations personnel promptly verified that there was no ongoing work requiring these instruments to be isolated and returned the pressure transmitters to service. The two pressure transmitters indicated correctly and ATWS was declared operable. The Nuclear Watch Engineer directed technicians to perform a partial valve lineup of RV pressure and level instruments in accordance with procedure 8.M.1-33, "Instrument Walkdown." All other instruments were found properly aligned. Immediate corrective actions by operations personnel were timely and appropriate.

The licensee initiated problem report (PR) 93.9341 to determine the root cause of the pressure transmitter isolation and establish corrective actions to preclude recurrence. Representatives from the various plant disciplines conducted a detailed event critique. Discussion of the maintenance history of the mispositioned valves resulted in determination that the pressure transmitters had been isolated during installation of the RV reference leg backfill modification. Technicians used procedure 3.M.2-12.4, "Backfilling Reference Lines for Rack 2205, 2275 &

2251 Instruments" to isolate the instruments and to restore the instruments to service on July 24. Two valves, labelled "isolation" valve and "rack isolation" valve, exist between the pressure instrument and the common sensing line. Procedure 3.M.2-12.4 instructs technicians to operate the "instrument isolation" valve. This naming convention was not uniformly understood and implemented by technicians. As a result technicians operated the wrong valves and two ATWS pressure instruments remained isolated when the reactor was restarted on July 25. Root cause of the event was attributed to inadequate procedural instruction which led to inconsistent implementation and valve operation by technicians. The licensee initiated revisions to procedures 3.M.2-12.4 and 3.M.2-12.3, "Backfilling Condensing Chambers 12B and 13B and Instrument Lines from Racks 2206, 2276, and 2252", to more clearly identify the valves to be operated for isolation or backfill. Instrumentation and Controls personnel validated similar procedures associated with RV pressure and level instruments and conducted training regarding proper isolation of transmitters. In addition, procedure 2.1.1 "Startup from Shutdown", was revised to require completion of daily RV pressure and level instrument checks prior to placing the operational mode selector switch in the "Run" mode.

Performance of an instrument lineup in accordance with procedure 8.M.1-33 prior to reactor startup would have identified and corrected the transmitter isolation valve misalignment. The inspector questioned why this procedure had not been performed prior to startup considering the RV reference leg modification and associated valve operations performed during the reactor shutdown period. The licensee stated that prior to reactor startup, they believed transmitter valve operations were not extensive during the outage and had been properly controlled through the use of procedure 3.M.2-12.4. The inspector verified that the pressure transmitter isolation valves were located outside of the RV reference leg modification work boundary and were only required to be operated during reference leg backfill. On this basis, the licensee decision not to perform an additional instrument lineup in accordance with procedure 8.M.1-33 was acceptable. However, the inspector also noted that procedures do not currently identify who is responsible to determine when and what portions of procedure 8.M.1-33 are to be performed. Subsequent revision to procedure 2.1.1 addressed this concern. The inspector concluded that the training and procedure revisions were appropriate to preclude recurrence.

Technical specifications require that a functional test of the ATWS system be performed prior to reactor startup. The functional test, consisting of injecting a simulated electrical signal into the measurement channel, was completed on July 24, 1993, in accordance with procedure 8.M.1-29, "ATWS Trip Unit Calibration Test." The licensee initial reportability assessment concluded that the functional test had been successfully performed and that this event was not reportable to the NRC. The inspector questioned the capability of the ATWS functional test to demonstrate system functionality with the two pressure transmitters isolated. Operations personnel had considered ATWS operable at the time that the operational mode selector switch was placed in the 'RUN' position, based on the completed functional test and the presumption that the transmitters were properly aligned. In this instance two ATWS pressure transmitters were not properly aligned. Upon further review following the event critique the licensee determined that this event was reportable to the NRC in accordance with 10 CFR 50.73. The inspector had no further questions and concluded that licensee corrective actions were appropriate.

3.0 MAINTENANCE AND SURVEILLANCE

3.1 Reactor Coolant Pressure Boundary Weld Repair

On July 22, 1993, the licensee conducted a drywell inspection to identify the source of unidentified water leakage which was being monitored in accordance with the PNPS Technical Specifications 3/4.6.C.1 as operational leakage. The increasing rate of suspected coolant leakage led to the decision to initiate a plant shutdown (see Section 2.2). The licensee discovered the leakage to be that from the reactor coolant pressure boundary, at a socket weld connecting a 2" reactor drain piping to a manual globe valve, HO-261-65, and the pipe line leading to the reactor water cleanup (RWCU) system. Since the leaking weld was located on the upstream side of the valve, the leak was unisolable through normal operational means.

Preparations

Problem Report 93-9335 was initiated to document the weld leak. Upon visual inspection of the defective weld, the licensee determined that a weld repair would be conducted. In order to drain the line for excavation of the weld and repair of the welding, installation of a freeze seal was required between the reactor vessel and valve HO-261-65. Isolation of the repair area from downstream sources of water in the RWCU system could be effectively accomplished by means of valve closures. In accordance with PNPS pipe freezing procedure, 3.M.4-90, a safety evaluation is required to be performed for application of freeze seals to other than austenitic stainless steel piping. Since both the 2" reactor drain piping and valve HO-261-65 are fabricated from carbon steel, ASTM A-105 forged material, Safety Evaluation 2771 was documented, reviewed and approved by the Operations Review Committee (ORC) on July 23, 1993, prior to the installation of the freeze seal and the commencement of weld repair activities.

The inspector reviewed SE 2771 and the PNPS procedure No. 3.M.4-90, and attended the ORC meeting when both were discussed. The inspector noted that industry experience with freeze seals (e.g., USNRC Information Notice 91-41) was adequately considered in the evaluation process, as were cautionary steps to minimize the potential for brittle fracture of the piping during and after freeze seal application, as well as contingency plans for a freeze seal failure. The inspector questioned the communications arrangements for the different work locations including the freeze seal apparatus under the reactor vessel, the weld repair at valve HO-261-65, the liquid nitrogen supply system and control point outside the drywell, and the control room. Appropriate plans and procedural controls were verified by the inspector to be in place.

The inspector also reviewed maintenance request 19302861 covering the weld repair preparation, conduct and post-work testing activities. The inclusion of quality control hold points, consistent with procedure no. 3.M.4-90 and the conduct of liquid penetrant examinations of the excavated weld area and the completed weld, were confirmed. The inspector examined the work package at the control point in the reactor building, checking procedural compliance, the record of pipe temperatures associated with the freeze seal application and the implementation controls for the required nondestructive examinations of both the piping and repaired weld.

Visual Examinations and Failure Analysis

Licensee analysis of the defective weld indicated that the most probable cause of the failure was the presence of water during welding of a replacement valve (i.e., the current HO-261-65) in March 1980. This conclusion was reached through visual examination of the weld, with the excavated area of defective material covering the lower half where water would collect and where the most difficult position for manual shielded metal arc welding (SMAW) is located. This conclusion was corroborated by a record review indicating problems with water in the pipe during welding in 1980, causing a revision to the welding procedure. The inspector reviewed plant records for the installation of this valve in 1980 (reference: plant design change, PDC 79-22) and for the replacement of the dissimilar metal weld on the other side of the valve in 1985 (reference: temporary modification, TM 85-12). The inspector checked that the socket weld configuration and size details complied with the requirements of the ASME B31.1 and ANSI B16.11 codes and reviewed BECo procurement and vendor records for the Conval globe valve to ensure other requisite code and material provisions had been met. The inspector also interviewed a cognizant BECo welding engineer and determined that the licensee root cause analysis of this weld failure was technically sound and supported by historical evidence. The licensee subsequently examined five other carbon steel socket welds on this 2" piping in the area of the failed weld and identified no additional problems. As a result of these inspections, the record reviews and the licensee analysis, the inspector concurred with the finding that the identified weld failure represented an isolated case, caused by unique welding problems encountered during the implementation of PDC 79-22 in 1980.

Hydrostatic Testing

On July 24, 1993, the inspector attended an ORC meeting to discuss Safety Evaluation 2772, which considered conduct of a hydrostatic pressure test of the repaired weld, at 1.1 times the nominal system operating pressure in accordance with ASME Section XI requirements. A safety evaluation was required to evaluate the use of a freeze seal to isolate the reactor pressure vessel from the elevated test pressure. The inspector reviewed SE 2772 and the test flow diagram identifying the boundary valves for the hydrostatic test. The inspector confirmed that the licensee had considered worst case scenarios (e.g., a 2" pipe failure, which is bounded by accident analysis) and potential freeze seal failure effects. The licensee also had discussed the intended hydrostatic test boundary usage of the freeze seal with the vendor and had been apprised of successful laboratory tests up to 2000 psig with cryogenically frozen pipes. The upper limit of the hydrostatic test planned at the PNPS was 1190 psig. Based upon this information and the conservative licensee approach to both evaluation and implementation of the freeze seal installation, the inspector had no questions or unresolved safety concerns regarding the post-work testing of the weld repair.

Conclusions

During the course of the inspection of the licensee response and repair to the weld leakage, the inspector witnessed a radiation protection briefing of BECo and contractor personnel entering the drywell to conduct planned liquid penetrant testing. The inspector also interviewed cognizant engineering, maintenance, quality control and operations personnel relative to the planned and ongoing work activities. Design specifications, isometric and in-service inspection (ISI) drawings, and maintenance work plans were reviewed, as necessary, to evaluate the adequacy of licensee work controls and compliance with design requirements (e.g., pipe and valve minimum wall considerations). Overall, the licensee demonstrated appropriate consideration of operational concerns in the conduct of the repair of the leaking weld (ISI no. 12-BC-15). A conservative approach to both the safety evaluations and contingency planning was in evidence and the proper ORC attention to the resolution of several interdisciplinary questions of safety importance was noted by the inspector. Similarly, all inspector questions and inspection issues regarding root cause analysis, design constraints and code compliance were adequately answered by the licensee. No unresolved safety concerns were identified. The inspector considers the conduct of this weld repair to represent a thoroughly planned and well executed, safety significant corrective maintenance activity.

4.0 ENGINEERING

4.1 Implementation of NRC Bulletin 93-03

Background

Pilgrim Station has observed reactor vessel (RV) water level indication "notching" (momentary false high level indication) following controlled plant shutdowns over the past few years. The cause of the notching was attributed to dissolved non-condensable gases, which had migrated downstream from the RV water level instrument condensing pot to the reference leg piping, coming out of solution during RV depressurization. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel (RV) Water Level Instrumentation in BWRs" requested certain licensee actions be taken to ensure high reliability of RV level instrumentation. Short term actions were specified to verify procedures were in place and operators were trained to respond to inaccurate RV level indication during transients and accidents initiated from reduced pressure conditions (Mode 3). Long term action consisted of a hardware modification to ensure the level instrumentation design is of high functional reliability for long term operation including both high and reduced pressure conditions. All short term actions were required to remain in effect until the long term hardware modification was completed.

Five separate RV level instrument condensing pot and reference leg assemblies tap off of the RV. Condensing pots condense steam from the RV and provide condensate make-up which maintains the associated reference leg piping full. Two of the five reference legs are associated with level instruments which service the feedwater control system. Two separate reference legs are connected to level instruments which provide inputs to protective systems which include the emergency core cooling system (ECCS), the reactor protective system, and the primary containment isolation system. These two are referred to as the ECCS reference legs. The remaining reference leg is connected to the shutdown level instrument which provides RV level indication used during RV flood-up evolutions such as refueling.

Training and Procedures

The licensee implemented plant design change (PDC) 93-25, "Reactor Water Level Computer Display" to provide operators with the capability to monitor one level instrument from each of the five RV level reference legs on a single display screen. Operators were then trained to use the enhanced monitoring capability in accordance with temporary procedure TP93-102, "NRC Bulletin 93-03 Short-Term Actions Reactor Level Monitoring." The inspector noted that the procedure incorporated a discussion of both Pilgrim specific and industry observed characteristics of potential RV level instrument inaccuracies. The inspector observed control room operators using the RV level computer display and determined that operators were knowledgeable and properly trained on PDC 93-25. Minor discrepancies, such as the inability of the display console to change scales as directed by procedure, were discussed with the chief operating engineer who initiated appropriate corrective action. Procedure instructions for enhanced monitoring and instrument comparison criteria were concise and clearly understood by the operators.

Temporary procedure TP93-102 was subsequently incorporated into procedure 2.2.80, "Reactor Vessel Level, Temperature, and Internal Pressure Instrumentation." The licensee revised several procedures to improve the control of valve lineups and maintenance that have the potential to drain the RV during reduced pressure conditions and to reduce the possibility of RV level transients. Additional training was conducted to alert operators to potentially misleading level indication that could occur during transients or accidents, including RV drain-down, initiated while the plant was shutdown. The inspector reviewed the selected procedures and training documentation, and concluded that the licensee had completed the appropriate training that satisfied the requested actions of NRC Bulletin 93-03.

Design Change

The licensee developed PDC 93-24, "Reactor Water Level Reference Leg Back Fill System" designed to prevent the migration of non-condensable gases down the ECCS reference legs by maintaining a continuous fluid back flow up the reference leg to ECCS condensing pots 12A and 12B during normal operation. This permanent hardware modification connects the control rod drive (CRD) charging water header to the ECCS reference legs at safety related instrument racks C2205 and C2206. The nominal backfill flow rate of .008 gallons per minute at normal operating pressure exceeds the estimated pot condensation rate to assure the direction of flow in the reference leg is toward the condensing pot. Engineering analysis determined that reactor operation could continue with the backfill system out of service for a period of up to fourteen days without concern for RV level notching during a subsequent reactor depressurization. The inspector confirmed that procedure 2.2.80 requires operators to implement enhanced RV level monitoring when the plant shuts down and depressurizes following a period of fourteen days in which the reference leg backfill system has not been in operation.

The fourteen day period was based on the maximum instrument rack leak rates measured at Pilgrim Station and the volume of the condensate pot and reference leg piping to the primary containment wall. The inspector reviewed calculation No. M585 and determined that it appropriately supported derivation of the fourteen day period required for noncondensable gases to travel from the condensing pot to the primary containment wall. The inspector then questioned the expected magnitude of RV level inaccuracy which could result following rapid RV depressurization after the fourteen day period, and subsequent capability to monitor RV level. The licensee stated that the calculated RV level indication would support operator monitoring of RV level to ensure adequate coolant inventory to cool the core as bounded in Section 7.8.5.2 of the Final Safety Analysis Report (FSAR). The inspector reviewed the FSAR basis and concluded that this reference leg depressurization event was appropriately analyzed and bounded by the FSAR.

Two safety related check valves were installed on each backfill system to ensure the reference leg inventory was maintained during periods when a CRD pump was not operating. These seismic class I check valves provide a class break and isolation in the event of a failure of the non-safety related upstream piping. Each check valve is located outside of containment and outboard of the excess flow check valve and restricting orifice, which provide RV isolation on instrument lines connected to the RV. Therefore the new check valves are not primary containment isolation valves. However, based on the importance of backfill system, the licensee added these check valves to the inservice testing program.

The majority of PDC 93-24 installation work was performed or pre-staged while the plant was at power following startup from refueling outage No. 9. Approximately four days of final system tie-in and testing awaited a reactor shutdown condition to be performed. The reactor was placed in cold shutdown on July 22, to repair a defective unisolable socket weld as described in Section 3.1. During this shutdown period, PDC 93-24 was completed and shutdown testing of the reference leg backfill system was performed. Licensee safety evaluation No. 2769 determined that implementation of PDC 93-24 did not constitute an unreviewed safety question as defined in 10 CFR 50.59. The inspector independently reviewed portions of PDC 93-24 and safety evaluation No. 2769 and concluded that this modification did not create an unresolved safety question. Licensee analysis of safety system impact, modification design, and supporting calculations were excellent. The inspector noted the design criteria, post installation test requirements, and supporting procedures to be comprehensive and thoroughly developed.

Post-Modification Testing

The inspector reviewed test procedure TP93-108 "Pre-operational Test of the Reactor Water Level Reference Leg Backfill System (PDC 93-24)", and monitored post installation testing. The test procedure was clear and specifically highlighted test events which had the potential to precipitate safety system actuations. The pretest briefing was effective and communications were properly established between the control room and in-plant testing stations. The test sequence placed the backfill system in service on one ECCS reference leg at a time, thereby using the other ECCS reference leg's instrumentation as a reference baseline for RV level indication. The test plan consisted of numerous plant evolutions and CRD system manipulations which could effect CRD flow, and as a result change the backfill flow rate. Test evolutions while shutdown included reference leg backfill initiation, variation of backfill flow rate, CRD pump start, CRD pump shift, CRD pump trip, shift of CRD drive water filters, continuous and step change control rod movement, full reactor scram, backfill filter bypass, and isolation of the backfill system. The test plan repeated most of these evolutions at normal operating pressure following reactor startup.

Control room operators closely monitored RV level indication and modification engineers continuously recorded RV level response throughout the test using the plant computer (EPIC). Operators observed that both trains of control room RV level indication associated with the ECCS reference legs tracked consistently. This was consistent with engineer evaluation of EPIC data and graphic displays of RV water level indication during the test. Incomplete venting of reference leg backfill piping resulted in a half scram protective signal when backfill flow was first established. In addition, EPIC data recorded minor level indication pulses of up to three inch magnitude resulting from a small pressure transient in the reference leg piping when backfill flow was established. These minor level pulses dissipated within seconds and did not reoccur during testing with backfill flow established. The test director was aware of backfill system sensitivity to valve repositioning and properly instructed technicians to manipulate backfill flow valves slowly to minimize the potential for an associated pressure transient on reference leg piping. Modification management, operations, and maintenance personnel worked closely together throughout the test. Test coordination and communications were excellent. The inspector independently reviewed the recorded EPIC data and concluded that both trains of RV level indication were accurate and were not adversely affected by CRD system transients.

The backfill flowrate slowly degraded during the first few days of system operation following reactor startup requiring frequent adjustment of the flow control needle valve. Flow degradation was attributed to small impurities in the CRD system and reference leg piping which fouled the backfill micron filter and plated out on the flow control needle valve. The inspector monitored operator reestablishment of the desired flowrate and subsequent replacement of the backfill system filter. The procedure for filter replacement was well written and properly implemented. After several days of system operation, backflow stabilized sufficiently that only minor weekly flow control valve adjustments were needed to maintain the design flowrate.

Plant design change 93-24 identified several system evolutions and periodic surveillances to be performed following successful testing of the reference leg backfill system and turnover to operations personnel. The inspector verified that these surveillances had been added to the master surveillance tracking program and were being implemented.

Conclusions

Plant design changes 93-24 and 93-25 were implemented to improve the reliability of RV level indication and to provide control room operators with enhanced monitoring capability. The engineering analysis, construction, and training for these modifications were of high quality. Of specific note was the fine level of detail and controlled implementation of the post installation test plan. Reactor vessel level indication responded as designed during and after reactor startup with the backfill system in service. The licensee intends to continue evaluating condensate pot temperatures during this operating cycle and RV level during subsequent reactor depressurizations to fully assess the effectiveness of PDC 93-24. The inspector had no further questions and determined that licensee actions had appropriately addressed NRC Bulletin 93-03.

4.2 Licensee Event Report (LER) Review

LER 93-09

LER 93-09, "Circuit Breaker Did Not Close During Planned Bus Transfer due to Loose Control Circuit Wire", dated June 2, 1993, describes the May 4 de-energization of safety-related 480 VAC load center B-6 due to failure of circuit breaker 52-102 to close. A loose wire to lug connection in the automatic transfer circuitry caused the breaker to remain open instead of closing as designed when a loss of voltage from supply bus B-2 was sensed. The inspector confirmed that deenergization of bus B-6 resulted in salt service water pump "C" and both trains of the low pressure coolant injection system becoming inoperable. The reactor was shutdown for a refueling outage with the reactor vessel head removed and reactor temperature 75 degrees at the time of the event. No irradiated fuel movement was in progress and both trains of core spray were available if needed for core cooling in the event of a loss of coolant accident. De-energization of B-6 was of no safety consequence due to plant conditions at the time of the event.

Operators reenergized load center B-6 from the normal supply bus (B-1) within five minutes. Permanent corrective action included successful lug replacement, retermination, and retest on May 5, 1993. Problem report 93.9215 was initiated to determine and address the cause of the loose lug. The LER was of high quality and properly addressed all reporting criteria. The complex response of electrical components to this event was accurately described. The inspector had no further questions.

LER 93-10

LER 93-10, "Start Up Transformer (SUT) Became De-energized During Testing While Shut Down", dated June 18, 1993, describes the May 19 inadvertent de-energization of the SUT due to personnel error during a planned test procedure. De-energization of the SUT resulted in momentary loss of power to all six of the station's 4160 VAC electrical distribution buses. Safety systems including the reactor protection system, containment isolation systems, and the emergency diesel generators responded as designed to the loss of power. Non-licensed personnel error caused the de-energization of the SUT. This event was further documented in NRC Inspection Report 50-293/93-09. The LER detailed the event accurately, documented corrective actions, and addressed the reporting criteria. The inspector had no further concerns.

5.0 PLANT SUPPORT

The inspector reviewed radiological controls in place as well as the radiological conditions of selected areas in the plant. Radiological protection technicians properly briefed station personnel on the content of radiation work permits applicable to their work assignments. The inspector observed good radiological practices by operations and maintenance personnel during routine tours and maintenance activities. Survey postings, radiological conditions and controls were appropriate with no discrepancies noted.

Selected aspects of plant physical security were reviewed during regular and backshift hours to verify that controls were in accordance with the security plan and approved procedures. This review concluded that performance was acceptable and included the following security measures: security force staffing; vital and protected areas barrier integrity; maintenance of isolation zones; behavioral observation and implementation of access control including access authorization and badge issue; searches of personnel, packages and vehicles; and escorting of visitors. Security force personnel continued to perform their duties in an alert manner.

6.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (30702)

6.1 Routine Meetings

At periodic intervals during this inspection, meetings were held with senior plant management to discuss licensee activities and areas of concern to the inspectors. At the conclusion of the reporting period, the resident inspector staff conducted an exit meeting on August 24 with licensee management, summarizing the preliminary findings. No proprietary information was identified as being included in the report.

6.2 Management Meetings

On July 15, NRC:Region I managers met with licensee management to discuss the recently completed refueling outage and recent mid-level management reassignments at Pilgrim Station. On July 28, NRC:Region I security specialists met with licensee management to discuss the licensee security program. On August 4, NRC:Region I management met with licensee representatives to discuss the licensee radiation protection program and the results of NRC Inspection 50-293/93-10.

6.3 Other NRC Activities

On July 28-29, three NRC:NRR reactor systems specialists conducted a review of the licensee's recently implemented reactor vessel water level modification. The review included design and installation considerations, test program implementation, and post installation system performance.