Enclosure 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

License No.	DPR-35
Report No.	96-06
Docket No.	50-293
Licensee:	Boston Edison Company 800 Boylston Street Boston, Massachusetts 02199
Facility:	Pilgrim Nuclear Power Station
Inspection Period:	July 29, 1996 - September 23, 1996
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EXECUTIVE SUMMARY

Pilgrim Nuclear Power Station
NRC Inspection Report 50-293/96-06

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers resident inspection for the period of July 29 through September 23, 1996.

Operations

The plant staff prepared for and effectively weathered the effects of Hurricane Edouard which passed to the east of PNPS. Operators responded well to the loss of line #355 (345 KV) offsite power line which occurred due to a fault offsite and remained unavailable for 12 hours. The direction to lower reactor power to 70% to mitigate the effects of the resultant transient if the other 345 KV offsite power line was lost demonstrated a good focus on nuclear safety. One concern was identified that related to which meteorological tower wind speed indicator (33 or 220 foot elevation) was intended to be used to implement the action to lower power within the condenser bypass capability. This represents a procedure weakness. (Section I.O1.2)

During a routine plant tour on September 19, 1996, a reactor operator astutely identified and investigated a through-wall leak on the channel of the "B" reactor building closed cooling water heat exchanger. BECo management conservatively decided to commence a controlled and timely, within hours of the discovery of the leak, reactor shutdown when they determined that the repair could not be performed online. Operators performed the shutdown in a professional and controlled manner. BECo initiated an operability determination for all four reactor and turbine building closed cooling water heat exchangers. This issue will remain an **inspector follow item (IFI) 50-293/96-06-01** pending review and evaluation of BECo's root cause analysis. (Section I.O1.3)

Operators bent the main refuel bridge mast during preparations for fuel movement in the spent fuel pool. An appropriate critique was held. Although operators tried to perform the correct action by removing foreign material from the spent fuel pool before it went into the skimmer surge tanks, they did not verify that the "dummy bundle" was not grappled to the mast before the bridge was moved. This was an example of performance ineffectiveness which resulted in damage to the mast and additional radiation exposure expended during repair efforts. The safety consequences were low since no nuclear fuel was involved in the incident and radiation exposure was within limits. No specific further follow-up is warranted at this time. (Section I.O2.1)

The starting air, turbo assist air and fuel oil storage and transfer support systems were properly aligned to support EDG operability. Minor fluid leaks were generally identified by BECo personnel as indicated by deficiency tags. The valve packing nut/bushing for valve 38-HO-193A was found fully unthreaded and hanging down from the valve bonnet. This deficiency was not previously identified by BECo personnel and reflected a missed opportunity for problem identification. (Section I.O2.2)

During a control panel verification done as part of shift turnover, a newly-licensed reactor operator alertly identified that valve MO-1001-16A ("A" RHR loop heat exchanger bypass) was closed vice open in the normal standby condition. Since the valve automatically repositions in response to an accident signal, a violation of RHR system operability did not occur. The valve became mispositioned when another reactor operator failed to follow the established RHR procedure when securing torus cooling 11 hours earlier. Apparently, the operator did not directly use the procedure, but reviewed the procedure and then relied on his memory to complete all actions. Several other operators missed earlier opportunities to identify the incorrect valve position during turnover activities. Plant management implemented meaningful short term corrective actions and initiated a detailed root cause analysis. (Section I.O4.1)

The plant status update (PSU) training held during operator requalification training rigorously discussed the lessons learned from the April 19, 1996 reactor scram. Enlarged computer traces were effectively utilized as training aids by the operations department manager during the review of reactor vessel level and pressure immediately following the reactor scram. As a result, NRC **IFI 50-293/96-03-01** is considered **closed**. The operations department training represented one element of a high quality self-assessment process. (Section I.O5.1)

The corrective action process was not effective in identifying and/or correcting a condition adverse to quality (an overall procedural adherence and adequacy problem) at Pilgrim following the identification of related problems since April 1995. This is a **Violation (VIO 50-293/96-06-02)** of the requirements of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions". With the opening of this violation, **Unresolved Item No.(URI) 96-80-03**, which addressed inadequate procedural use of PNPS, is considered **closed**. The inspector noted BECo has several corrective actions in progress to correct the issue. BECo's ongoing common cause analysis is broad in scope, including a review of problem reports issued for the past 12 months. While adequate overall, BECo's June 17, 1996 response was weak in certain instances, in that it did not communicate a clear, integrated plan to correct the identified problems. Also, no specific date for completion of all corrective actions was cited. (Section I.O7.1)

Licensee Event Report (LER) 50-293/95-004-00: Drywell-to-torus vacuum relief system actuation while de-inerting the drywell was closed. The inspector considered the revision to PNPS 2.2.70 appropriate to prevent recurrence. (Section I.O8.1)

Maintenance

Knowledgeable operators, maintenance and instrumentation and control technicians generally performed surveillance and maintenance activities in a controlled and professional manner, utilizing approved procedures and work packages. For example, the WIN team leader provided effective oversight of the corrective maintenance to replace two broken belts on service water room ventilation fan VEX-104A. Operators had to manually rack a 4160 volt breaker (A603), designed to be automatically racking, into service due to a deficient test box racking switch and racking motor connections. Operators took the prescribed electrical precautions by wearing a full set of electrical protective clothing. (Section II.M1.1)

The training given this period on the work control process procedure was a positive work control department initiative to update the nuclear organization on several changes made to the process since it was first adopted in 1995. (Section II.M5.1)

The questioning attitude of a new BECo maintenance supervisor identified a deficiency with the dimensions of a service water pump shaft gib key prior to installation. As a result, the work to replace the gib key on the "A" SSW pump was placed on hold. The replacement key had been previously accepted by a QC inspector. As an initiative, the inspector expanded review of this receipt and inspection issue by reviewing several MRIR packages. A condition adverse to quality **(VIO 96-06-02)** was identified that involved the Rockwell Hardness Tester machine which exhibited calibration problems that were not promptly identified and corrected. Several peripheral issues also became apparent during this review indicating levels of informality existed in the receipt and inspection area. (Section II.M7.1)

Unresolved Item 50-293/94-18-04, Core spray keepfill system isolation valve leakage rate criteria, was **closed** this period because BECo has completed a radiological evaluation of keepfill system leakage and is tracking the establishment of new acceptance criteria. Also, **LER 50-293/95-001-00**, Reactor building-to-torus train "C" vacuum relief system actuation while operating, was **closed**. (Sections II.M8.1 and II.M8.2)

Engineering

BECo responded promptly to reactor water and offgas indications of leaking nuclear reactor fuel in August 1996. Chemistry personnel quickly identified the indications and communicated them to the organization so that a root cause evaluation and corrective actions could be initiated in a timely manner. An action plan was developed and implemented to conduct reactor core power suppression testing. Reactor engineering, chemistry, and operations support personnel effectively communicated with General Electric and Centec to execute a controlled, well-planned process to identify the leaking fuel cell. Power suppression briefings were thorough and contributed to professional execution of the testing. BECo chemistry and reactor engineering personnel communicated well with General Electric to determine a safe control rod pattern and examine the results of subsequent chemistry data to evaluate the effectiveness of the power suppression. (Section III.E2.1)

Previous corrective actions for slow EDG start times did not thoroughly and completely address the problem. The current approach reduces the probability of simultaneous failure of the turbo assist solenoid valves; however, a real possibility exists for such a failure. The valves operate in an environment that is known to be detrimental and that will inevitably cause malfunction. BECo is relying on detection of valve failure (through frequent testing) to avoid loss of system function, rather than prevention of failure. BECo reported that individual solenoid valve failures have been identified on two occasions since the increased testing frequency was adopted. This item **remains unresolved (UNR 94-26-01)** pending accumulation of additional data for trending and evaluation. (Section III.E8.1)

Plant Support

The decision to take a broad look at problems identified with operations support center (OSC) ability to dispatch, track, and prioritize teams was positive. Emergency preparedness personnel trained emergency response personnel on draft procedure revisions to obtain feedback to make the procedures clearer and more effective. In addition, the procedures were aggressively validated during an activation drill in which they were used. (Section IV.P3.1)

After a leak was discovered in the water jacket of the diesel fire pump, BECo personnel declared the pump inoperable and entered the appropriate UFSAR Limiting Condition for Operation (LCO) action statement. The action to perform a temporary weld repair to the manifold, instead of remaining in the loss of redundancy procedure until the replacement part could be obtained, was evidence of a strong commitment to plant material condition and sensitivity towards UFSAR information. (Section IV.F2.1)

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REPORT DETAILS

Summary of Plant Status

Pilgrim Nuclear Power Station (PNPS) began the period operating at approximately 100 percent rated power. On August 23, operators reduced reactor power to approximately 60 percent to perform planned power suppression testing of the nuclear fuel. Operators returned the reactor to 100 percent rated power on August 28 where it was maintained until August 31. On August 31, power was reduced to approximately 70 percent to perform maintenance on control rod 02-27 and scheduled control rod exercising. Later that night, operators again returned power to approximately 100 percent.

Power was reduced twice during the remainder of the period to perform backwashes of the main condenser. Power was reduced to approximately 50 percent for the first backwash on September 3. Operators returned power to 100 percent on September 4. Over that weekend, on September 7, operators reduced power to 50 percent to perform a thermal backwash of the main condenser. Power was returned to 100 percent on September 8 where it remained until September 17.

On September 17 a reactor operator discovered a leak on the salt service water side of the "B" reactor building closed cooling water (RBCCW) heat exchanger. Plant management directed that the unit be shutdown to facilitate repairs to the RBCCW heat exchanger. The shutdown was initiated at approximately 9 p.m. that night. On September 17, 1996, operators made a formal notification (Event Number 31017) to the NRC headquarters operations officer to report the initiation of a plant shutdown required by technical specifications because PNPS staff determined that the "B" RBCCW heat exchanger could not be repaired on line. The report was made pursuant to 10 CFR 50.72(b)(1)(i)(A). Further details of this shutdown are discussed in Section I.O1.3. The generator was taken off line at 1:50 a.m. September 18. Cold shutdown was achieved at 8:30 p.m. on September 18, where the reactor remained through the end of the period.

I. OPERATIONS

O1 Conduct of Operations[1]

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspector conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety conscious. During tours of the control room, the inspector discussed any observed alarms with the operators and verified that they were aware of any lit alarms and the reasons for them. Any anomalies noted during tours were discussed with the nuclear watch engineer (NWE). A control room panel, residual heat removal (RHR) system digital total flow indicator (FT-1049B) displayed erroneous readings during the period. FT-1049B indicates -4999 gallons/minute with no RHR pump running. Repair efforts made during this period

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[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

were not effective. Overall, the number of control room deficiencies decreased slightly. Other specific events and noteworthy observations are detailed in the following sections.

O1.2 Hurricane Edouard

a. Inspection Scope (93702)

On September 1 and 2, 1996, Hurricane Edouard passed near the PNPS. Initial weather forecasts projected that the hurricane could possibly strike the greater Plymouth, Massachusetts area, and as such a hurricane warning was posted. During deep backshift inspection, from 8:45 p.m. to 7:15 a.m., the inspector monitored BECo preparations for and the actual impact of Hurricane Edouard. NRC Region I staffed the Incident Response Center with management and technical personnel. Several NRC conference calls were conducted to discuss and monitor the effects of Hurricane Edouard. The NRC Region I Administrator, Mr. Hubert Miller, dispatched two inspectors by a four wheel drive vehicle from NRC Region I with a portable satellite telephone system to be used as a contingency if adverse weather conditions disabled the normal telephone lines. This action resulted directly from a lesson learned during a past hurricane at the Turkey Point Nuclear Power Station. The portable satellite telephone arrived at PNPS at approximately 3:00 a.m. Prior to arrival of the adverse weather, the plant staff entered procedure 2.1.37, Coastal Storm - Preparations and Actions. Many precautionary actions were taken such as securing onsite equipment located outside. Procedure 5.2.2, High Winds (Hurricane), provides additional actions including the criteria to lower reactor power in preparation for an impending loss of offsite power (LOOP) and start the emergency diesel generators (EDGs).

b. Observations and Findings

During the storm, two operators remained stationed in the intake structure with all four travelling screens in operation. Every hour the NWE contacted a local weather forecaster to track the path of Hurricane Edouard. The approximate maximum wind speeds observed at PNPS were 50 mph sustained on the upper (220 foot elevation) and 30 mph sustained on the lower (33 foot) elevation of the meteorological (MET) tower. The hurricane passed to the east of the plant with minimal effects experienced at the site.

At 6:45 a.m. on September 2, one of the two 345 KV offsite power lines (i.e., Bridgewater 355 line) tripped due to a fault offsite. Line 355 remained down for approximately 12 hours. The plant manager ordered that reactor power be reduced to 70% to mitigate the potential effects of a total loss of offsite power (LOOP). This action represented a good focus on nuclear safety. After offsite power line 355 was restored, operators returned the unit to full power without incident. Lastly, some momentary fluctuations occurred on the 23 Kv offsite power line that feeds the shutdown transformer.

One concern identified by the inspector involved the interpretation of a procedure step. Procedure 5.2.2, Rev. 17, Step 4.0[2] stated, in part, that if winds reach hurricane velocities (greater than or equal to 75 mph) near the site then notify REMVEC and reduce power to load rejection capabilities. Although wind speeds never reached 75 mph at PNPS during Hurricane Edouard, the inspector noted that the NWE intended to use the 33 foot elevation reading which indicated approximately 20 mph lower than the 220 foot elevation wind speed indicator. No clear basis existed for using the 33 foot elevation rather than the higher reading indicator at the 220 foot elevation. The inspector expressed concern to BECo that some ambiguity existed in the procedure and/or operator knowledge as to which wind speed indicator should be used to implement actions of Procedure 5.2.2. Subsequently, operations support personnel issued revision 18 to Procedure 5.2.2 that provided more specific guidance to use the highest indicated wind speed on either the 33 or 220 foot elevation, which is most conservative. The procedure change addressed the inspector's concern.

c. Conclusions

The plant staff prepared for and effectively weathered the effects of Hurricane Edouard which passed to the east of PNPS. Operators responded well to the loss of the 355 offsite power line which occurred due to a fault offsite and remained unavailable for 12 hours. The direction to lower reactor power to 70% to mitigate the effects of the resultant transient if the other 345 KV offsite power line was lost demonstrated a good focus on nuclear safety. One concern was identified that related to which meteorological tower wind speed indicator (33 or 220 foot elevation) was intended to be used to implement the action to lower power within the condenser bypass capability. This represents a procedure weakness.

O1.3 Plant Shutdown Due to Through-Wall Leak in RBCCW Heat Exchanger

a. Inspection Scope (71707)

At 9:00 p.m. on September 17, 1996, operators commenced a controlled shutdown of PNPS after a reactor operator (RO) discovered a through-wall leak on the salt service water (SSW) side of the "B" reactor building closed cooling water (RBCCW) heat exchanger. The inspector observed portions of the shutdown in the control room, reviewed the technical specification requirement for the RBCCW system, observed portions of the repair to the heat exchanger, and discussed the leak with operations and engineering management.

b. Observations and Findings

During a routine operator tour on the afternoon of September 17, 1996, a licensed reactor operator observed water dripping on the floor near the "B" RBCCW heat exchanger (one of two containment cooling system loops). Upon removing the anti-sweat insulation on the channel of the heat exchanger, a through-wall leak and 2.5 inch longitudinal crack on the inlet side of the heat exchanger channel near the lower partition plate was discovered. Plant personnel decided that the repair could not be performed on line and therefore commenced a reactor shutdown.

The inspector reviewed PNPS Technical Specification (TS) Section 3.5.B, Containment Cooling System, which allows continued plant operation for 72 hours with one loop of containment cooling inoperable. The inspector found BECo's action to immediately commence a controlled shutdown conservative. During the shutdown, the inspector observed an operator stationed in the area near the leak to report any further degradation to the control room. Although the crack did appear to grow to approximately 6 inches, the reduced flow/pressure through the heat exchanger did not worsen the leak.

The inspector observed operators perform the shutdown in a controlled, professional manner in accordance with procedure 2.1.5, Controlled Shutdown From Power. Operators inserted control rods in the reverse order of the pull sheet, monitored and maintained cooldown rate within the requirements, and maintained reactor water level within the designated band. Appropriate limiting conditions for operation (LCOs) were entered and tracked in the LCO log for plant conditions.

During the day on September 18, a rain storm occurred in the area. The inspector noted that winds gusted to 60 mph, as indicated on the control room 220 foot elevation meteorological tower wind recorder. The inspector discussed this condition with the NWE who reviewed related procedures for coastal storms and hurricanes. The inspector verified that entry into the hurricane procedure was not required and appropriate actions had been taken to secure outside equipment.

Control room operators made a formal notification (Event Number 31017) to the NRC headquarters operations officer to report the initiation of the plant shutdown required by technical specifications. The report was made pursuant to 10 CFR 50.72(b)(1)(i)(A). In addition, through discussion with plant management and review of operator logs, the inspector noted that state and local officials were also notified of the shutdown. The inspector also verified that no emergency action level entry conditions were reached during this shutdown.

The two RBCCW heat exchangers are u-tube design with two passes of SSW through the tubes to cool the RBCCW water which then cools plant equipment. The channel portion of the heat exchanger accepts the inlet SSW, directs it through tubes for the first u-tube pass, receives and redirects SSW for the second pass, and receives the outlet water and directs it to the SSW outlet piping. Two partition plates are welded to the channel to direct the salt service water flow through the heat exchanger tubes. The heat exchangers are made of 90-10 copper nickel and are designed to the same specifications, although the "A" heat exchanger typically has less duty due to the fewer loads it cools.

The anti-sweat insulation was removed from the channel of the "A" RBCCW heat exchanger and a liquid penetrant (pt) examination was performed on its outer surface. The inspector examined this channel and did not detect any cracking or deformation in the channel as was seen on the "B" heat exchanger. After the "B" RBCCW heat exchanger was drained, the channel was removed to facilitate a 100% interior visual inspection and weld repair of two identified longitudinal cracks. Both the original and subsequently identified cracks were located on the inlet side of the channel near the partition plate.

Problem Report (PR) 96.9473 was initiated to document the identified through-wall leak and determine the root cause corrective actions. At the end of the report period, the examination of and repairs to the "B" RBCCW heat exchanger; root cause analysis, and operability determinations for all four heat exchangers, including the "A" and "B" turbine building closed cooling water heat exchangers, were not yet completed. This issue will remain an **inspector follow item (IFI) 50-293/96-06-01** pending review and evaluation of BECo's root cause analysis.

c. Conclusions

During a routine plant tour on September 19, 1996, a reactor operator astutely identified and investigated a through-wall leak on the channel of the "B" reactor building closed cooling water heat exchanger. BECo management conservatively decided to commence a controlled and timely, within hours of the discovery of the leak, reactor shutdown when they determined that the repair could not be performed online. Operators performed the shutdown in a professional and controlled manner. BECo initiated an appropriately scoped operability determination for all four reactor and turbine building closed cooling water heat exchangers. This issue will remain an **inspector follow item (IFI) 50-293/96-06-01** pending review and evaluation of BECo's root cause analysis.

O2 Operational Status of Facilities and Equipment

O2.1 Bent Refuel Bridge Mast During Preparation For Fuel Movement in Spent Fuel Pool

a. Inspection Scope (71707)

On September 3, 1996, during preparations for fuel movement in the spent fuel pool, operators bent the refuel bridge mast. The inspector discussed the incident with the involved reactor operators, attended the critique, reviewed immediate corrective actions taken, and subsequently observed operators move fuel in the spent fuel pool.

b. Observations and Findings

On September 3, 1996, the inspector learned that in the course of preparing the bridge for the fuel movement, the refuel bridge mast, used to move fuel bundles in the pool, had been bent. The September 4 critique was held in accordance with procedure 1.3.36, Conduct of Critiques and Incident Investigations. The critique was chaired by the Operations Department Manager to gather facts, ensure the plant was in a safe condition, and implement immediate corrective actions. The inspector noted that both the senior reactor operator (SRO) and RO involved in the event were present at the critique.

Operators were in the process of performing procedure 4.3, Fuel Handling, Attachment 5, Daily Refueling Checklist, Step [9], which verifies that the "Hoist Loaded" light is lit when a fuel bundle or "dummy bundle" is picked up. To perform this step, a "dummy bundle", a device which has the same relative weight and geometry as a fuel bundle but contains no nuclear fuel, was grappled onto the refuel bridge mast. During this step, the "ORC" key which allows fuel movement, was inserted. During this process, the key's flotation device and I.D. tag were disconnected from the key and fell into the spent fuel pool. The operators attempted to retrieve the device before it floated into the skimmer surge tank by raising the mast and moving the bridge forward. However, the RO had not ungrappled the "dummy bundle" before the bridge was moved. When the SRO went to verify that nothing was grappled, he saw that the bundle was still attached and directed the RO to discontinue the attempt to retrieve the foreign material. The movement of the mast with the "dummy bundle" grappled but not cleared of the spent fuel pool storage racks bent the outer telescopic section of the main mast.

The "dummy bundle" was lowered into the spent fuel pool rack and ungrappled and the mast was raised and pinned in place. A radiological protection (RP) technician was notified and retrieved the flotation device and I.D. tag from the pool. Problem Report 96.9437 was issued to document the event and conduct a root cause analysis.

The inspector noted that appropriate questions were asked at the critique and the plant was properly verified to be in a safe condition. No fuel damage occurred as a result of this event since a "dummy bundle" was grappled to the mast instead of a fuel bundle.

The root cause analysis was not completed at the close of the inspection period. However, the inspector verified that procedure 4.3 was revised to address other issues raised during the critique. In addition, the inspector subsequently observed operators relocate fuel bundles and control rod blade guides in the spent fuel pool. Operators used proper self-checking techniques and correctly followed the procedure. No problems were identified. No specific further follow-up is warranted at this time.

c. Conclusions

Operators bent the main refuel bridge mast during preparations for fuel movement in the spent fuel pool. An appropriate critique was held. Although operators tried to perform the correct action by removing foreign material from the spent fuel pool before it went into the skimmer surge tanks, they did not verify that the "dummy bundle" was not grappled to the mast before the bridge was moved. This was an example of performance ineffectiveness which resulted in damage to the mast and additional radiation exposure expended during repair efforts. The safety consequences were low since no nuclear fuel was involved in the incident and radiation exposure was within limits. No specific further follow-up is warranted at this time.

O2.2 Emergency Diesel Generator Safety System Walkdown

a. Inspection Scope (71707)

The inspector performed a safety system verification of the following emergency diesel generator (EDG) systems: 1) diesel oil storage and transfer system (P&ID M222); 2) diesel generator air start system (P&ID M219); and 3) diesel generator turbo assist system (P&ID M259). For each system, the inspector reviewed the applicable operating procedure and P&ID and generally performed a hand-over-hand walkdown of component configurations. The EDGs were selected for review based on their risk significance during accident conditions.

b. Observations and Findings

All EDG support system components were found in the normal position to support EDG safety system operability. A special emphasis was placed on verifying locked valves to ensure the locking devices were installed and effective in restricting operation. Existing fluid leaks were generally identified by BECo personnel as evidenced by deficiency tags. For example, both leaks on the "A" fuel oil transfer pump and water fire suppression valves had deficiency tags affixed. A few minor concerns were raised by the inspector that did not affect EDG system operability. A few quarts of oil collected in the catch pan under the "A" EDG on the side closest to the engine driven blower that needed to be wiped up. Also, valve 38-HO-193A, the "A" EDG day tank level instrument lower drain root valve, had a small oil leak. Upon closer examination, the inspector observed that the single valve packing gland nut/bushing was fully unthreaded and hanging down approximately one inch away from the valve bonnet. The inspector notified the assistant operations department manager who threaded the gland nut back on and initiated a problem report to review the root cause.

c. Conclusions

The starting air, turbo assist air and fuel oil storage and transfer support systems were properly aligned to support EDG operability. Minor fluid leaks were generally identified by BECo personnel as indicated by deficiency tags. The valve packing nut/bushing for valve 38-HO-193A was found fully unthreaded and hanging down from the valve bonnet. This deficiency was not previously identified by BECo personnel and reflected a missed opportunity for problem identification.

O4 Operator Knowledge and Performance

O4.1 RHR Heat Exchanger Bypass Valve, MO-1001-16A, Mispositioned

a. Inspection Scope (71707)

On 7/31/96, an oncoming RO identified that MO-1001-16A, the "A" RHR heat exchanger bypass valve, was closed vice in the normal open position as specified by procedure 2.2.19, Residual Heat Removal. In the event of an accident, MO-1001-16A would have automatically closed as designed; therefore, the RHR system would still have performed the intended design function. Problem Report (PR) 96.9383 was initiated to document, evaluate and implement corrective actions, as needed. The inspector attended a critique held on July 31, 1996 to review the event circumstances and identify any lessons learned. The problem assessment committee (PAC) designated PR 96.9383 Priority 1 requiring a detailed root cause analysis. The detailed root cause analysis was not completed by the end of this routine inspection period on September 23, 1996.

b. Observations and Findings

At the critique held on July 31, 1996, the operations department manager established that operators placed the "A" loop of the RHR system into the torus cooling mode at 0100 on July 30, 1996 to facilitate a chemistry sample of the torus water. After the chemistry sample, the RO secured torus cooling at approximately 1225. The RO stated that he did not use Procedure 2.2.19, but did state that he reviewed the procedure prior to securing torus cooling, essentially relying on his memory to complete the necessary actions. After securing the "A" RHR pump, the RO reported to the NOS that torus cooling had been secured. The NOS failed to independently verify the actions taken by the RO by readily accepting that the proper actions had been taken. Approximately 11 hours later, an oncoming RO identified that the subject valve was closed instead of open. The oncoming RO opened MO-1001-16A.

The failure to open MO-1001-16A when securing torus cooling violated step 7.1.2[10]e of Procedure 2.2.19 which specified to open MO-1001-16A. Earlier opportunities to identify the mispositioned valve were missed during the 1500 RO shift change and later during the 1900 SRO shift change.

As a precaution, the operations department manager ordered a verification of all safety systems by control room panel walkdowns. No other configuration control problems were identified. Plant management initiated accountability measures, to varying degrees, with all operators involved. The immediate corrective actions included the opening of MO 1001-16A, verification of all safety system configurations, issuance of a PR, implementing accountability measures and holding a critique. The inspector determined that the short term corrective actions adequately addressed the issues.

In the longer term, a detailed root cause analysis has been initiated by the operations support group. The inspector notes that the RO who identified the mispositioned valve was a newly-licensed operator and that a few of the other operators who didn't identify the mispositioned valve had a considerable amount of operating experience. This example of inadequate procedural implementation reinforces the importance of the performance problems discussed in Section I.O7.1 of this report.

c. Conclusions

During a control panel verification done as part of shift turnover, a newly-licensed reactor operator alertly identified that valve MO-1001-16A ("A" RHR loop heat exchanger bypass) was closed vice open in the normal standby condition. Since the valve automatically repositions in response to an accident signal, a violation of RHR system operability did not occur. The valve became mispositioned when another reactor operator failed to follow the established RHR procedure when securing torus cooling 11 hours earlier. The operator did not directly use the procedure, but reviewed the procedure and then relied on his memory to complete all actions. Several other operators missed earlier opportunities to identify the incorrect valve position during turnover activities. Plant management implemented meaningful short term corrective actions and initiated a detailed root cause analysis. However, this is another example of a condition adverse to quality (procedural adherence problem) that was not adequately corrected as discussed in Section I.O7.1 of this report.

O5 Operator Training and Qualification

O5.1 (Closed) Plant Status Update (IFI 50-293/96-03-01)

a. Inspection Scope (71707, 92901)

Inspector follow item (IFI) 50-293/96-03-01 documented three operator training issues related to the April 19, 1996 automatic scram and subsequent start-up. When stabilizing plant conditions following the scram, several nonsafety related equipment problems slightly hindered the operator response. Nonetheless, the operators were able to gain control of key parameters without the automatic initiation of safety related injection systems or actuation of the code pressure relief valves. The inspector attended the plant status update (PSU) training held in the Chiltonville training center on August 6, 1996. The operations department manager (ODM) acted as the facilitator during the licensed operator requalification training (LORT). The PSU covered a detailed analysis and lessons learned from the April 19, 1996 event.

b. Observations and Findings

The operator training staff prepared detailed, written training material used during the presentation. An enlarged color-coded EPIC trace was used to illustrate key parameters, such as reactor vessel pressure and level, while reviewing integrated operator performance. The training lasted approximately 5 hours. Another key lesson learned was developed during the conduct of training.

One concern listed in NRC IFI 96-03-01 involved the control of reactor vessel water level immediately after the reactor scram. The reactor scram occurred from 22% reactor power, with the feedwater controls in single element (level) control. When reactor vessel level initially decreased, the operating feed water regulating valve ("B") opened widely injecting subcooled feedwater. A main steam isolation valve (MSIV) closure occurred approximately two minutes after the reactor scram due to high reactor vessel water level. The high water level resulted from the normal "swell" effect as the colder feedwater heated up and also due to steam leakage from a nonsafety related gland seal relief valve (unknown to the operator at the time of the malfunction) which allowed a more rapid pressure decrease exaggerating the reactor vessel water "swell" effect. Excluding the unexpected relief valve effect, the "swell" effect tends to be more pronounced during scrams from lower power levels.

Further on the first concern, efforts to equalize pressure around the MSIVs to reopen the MSIVs were hampered when MO-220-3, a nonsafety-related main steam drain valve, failed to open by control room switch. As a result of the MSIV closure which isolated the condenser as a heat sink for decay heat removal, operators had to manually use safety relief valves (SRVs) as an alternate means of pressure control. The high pressure coolant injection (HPCI) system was started in the full flow test mode for pressure control, but isolated several times due to the high reactor vessel water level. Another lesson learned developed by the ODM was that reactor vessel water level had to be sufficiently below the MSIV closure setpoint before starting the HPCI turbine; otherwise, the subsequent "swell" due to starting the steam driven HPCI turbine could cause isolation of HPCI system, as did occur. Another alternative could have been to start the reactor core isolation cooling (RCIC) turbine which is much smaller than the HPCI turbine and could have remained in service. The inspector notes that this lesson learned was developed during the training and was not directly reflected in the written material prepared by the training staff.

The second concern related to a reactor operator who had difficulty operating the generator field breaker switch. The operator tried to operate the switch handle by rotating it without pulling up at the same time. The design of the switch was reviewed during the PSU training. Specifically, the generator field breaker switch must be pulled and turned to trip the breaker. This was an example where the use of the prescribed self verification (STAR) process was lacking because the switch label plate states "Pull to Trip".

In the final instance, the reactor protection system received a half scram signal when the "C" intermediate range monitor (IRM) was not ranged up in time consistent with the increasing neutron population. The related IRM chart recorder pen stuck and as a result the operators inadvertently did not range up to a higher IRM scale. The chart recorder had a deficiency tag attached indicating that a stripped gear needed corrective maintenance.

c. Conclusion

The plant status update (PSU) training held during operator requalification training rigorously discussed the lessons learned from the April 19, 1996 reactor scram. Enlarged computer traces were effectively utilized as training aids by the operations department manager during the review of reactor vessel level and pressure immediately following the reactor scram. As a result, NRC **IFI 50-293/96-03-01** is considered **closed**. The operations department training represented one element of a high quality self-assessment process.

O7 Quality Assurance in Operations (40500)

O7.1 Corrective Action Failure to Identify Overall Procedure Adherence/Adequacy Problem

a. Inspection Scope

NRC inspection report 50-293/96-80, dated April 16, 1996, documented the NRC staff's identification of BECo's failure to identify and correct broad procedural usage and adequacy problems at PNPS and specific examples were described as apparent violations. The cover letter to that report requested BECo's perspectives on the areas identified. The inspector reviewed IR 96-80, the examples of poor procedure usage and adequacy delineated in that report, BECO's response to 96-80 dated June 17, 1996, and BECo's actions in this area to date. Section I.O4.1 of this report documents a recent example of poor procedural usage that resulted in a safety related valve left in the wrong position. Section II.M7.1 of this report documents a condition adverse to quality in that a Rockwell Hardness Tester machine exhibited calibration problems that were not promptly identified and corrected.

b. Observations and Findings

The inspector confirmed several instances of procedural adequacy and adherence problems previously identified in IR 96-80. For example, Procedure 2.2.87, Control Rod Drive System, Revision 53, was inadequate in that it did not provide direction to operators moving reactor fuel to verify the correct orientation of the blade guide before control rod insertion. As a result, on April 30, 1995, a control rod was inserted into the reactor into a mispositioned blade guide, causing potential blade guide and control rod damage. In this case, BECo's subsequent root cause analysis identified the procedure as less than adequate.

Procedure 9.13, Control Rod Sequence and Movement Control, Revision 12, Attachment 3 listed control rods to be moved, what position they were supposed to be at initially and where they were to be moved to. During the rapid power reduction required on October 6, 1995, operators were to insert rods in the reverse order of this pull sheet. However, rod 34-23 was mispositioned during the power reduction. The licensee's root cause analysis identified the procedure as less than adequate in that it was not easy to read for such a rapid power reduction. The analysis did not identify a failure to follow the procedure. The inspector reviewed the Attachment used at that time and agreed that the rapid power reduction array attachment subsequently developed was more "user friendly" but that the listing provided to the operator at the time was clear and legible.

In January 1996, the NRC questioned why NSRAC was not reviewing Priority Level 1 PR valuations. Subsequently, BECo confirmed that Nuclear Operating Procedure NOP 92A1, "Problem Report Program," Step 6.5.3, which directs that Severity Level I problem report evaluations be forwarded to NSRAC for their review, was inadvertently not being followed. Problem Report 96.0025 documented that approximately one third (60 out of 170) of the Level I PRs had not been forwarded to the NSRAC.

Section I.O4.1 of this report describes another example of procedural adherence problems. On July 31, 1996 valve MO-1001-16A ("A" RHR loop heat exchanger bypass) became mispositioned when a reactor operator failed to follow the established RHR procedure when securing torus cooling. The valve was mispositioned for approximately 11 hours.

In February 1995, a calibration problem on the "B" scale of the Rockwell Hardness Tester machine was adverse to quality and was not promptly identified or corrected. Quality control inspectors relied on verbal advice from an outside vendor rather than contacting the BECo measurement and test equipment personnel, as specified in the M&TE program, or initiating a problem report. Also, the degradation of a related BECo calibration block has not adequately been addressed to date. This item is described in Section II.M7.1 of this report.

Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B, states, in part, that, "...measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition." Although BECo did identify procedural adherence and/or adequacy as a root or contributing cause in some instances mentioned above and took corrective actions to correct the specific cases, they failed to identify an overall procedural adequacy/usage problem at the station and take broader corrective actions at the time of NRC Inspection Report 50-293/96-80. The two additional examples noted in this report reflect the ongoing nature of the low severity level problems.

In January 1996, as a result of BECo-identified concerns regarding the corrective action program and in response to an external industry auditing group finding that addressed a weakness in this area, FPI International was contracted to investigate human performance concerns in the PNPS operations department and make recommendations for improvement. In June 1996, select BECo personnel were trained in organizational/programmatic and human performance investigation techniques to improve BECo's consistency in analyzing problems. In addition, a detailed review of 12 months of problem reports, June 1995 to June 1996, and a common cause analysis was in progress during this period using the recently adopted analysis techniques. An independent oversight team (IOT) was formed to assist in performance monitoring and trending, review of self-assessments, root cause analysis, human performance issues, common causal factors and corrective action effectiveness. A human performance monthly trend report was developed to provide meaningful information to management.

On August 26, 1996, following the NRC's 96-80 inspection, BECo issued PR 96.0331 to conduct a formal root cause analysis to determine why station management and independent oversight groups were not successful in self-identifying procedure usage performance problems and developing and implementing corrective actions necessary to preclude recurrence. This analysis identified the root cause as procedures less than adequate, in that the problem report process did not provide consistent depth of analysis and performance monitoring capabilities to inform management of adverse trends in procedural usage that were contributing to some of the operational events occurring at PNPS. The analysis also identified several contributing causes including human factors and supervision less than adequate.

The inspector also reviewed BECo's June 17, 1996 response to concerns that were raised in NRC Inspection Report 50-293/96-80. The inspector considered this response in general to be adequate but weak in certain instances in that it did not communicate a clear, integrated plan to correct the identified problems. Also, no specific date for completion of all corrective actions was cited.

c. Conclusions

The corrective action process was not effective in identifying and/or correcting several examples of adversity to quality at Pilgrim following the identification of related problems since April 1995. This is a **Violation (VIO 50-293/96-06-02)** of the requirements of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions". With the opening of this violation, **Unresolved Item (URI) 96-80-03**, which addressed inadequate procedural use, is considered **closed**. The inspector noted BECo has several corrective actions in progress to correct the issue. BECo's ongoing common cause analysis is broad in scope including a review of problem reports issued for the past 12 months. Although adequate overall, BECo's June 17, 1996 response was weak certain instances in that it did not communicate a clear, integrated plan to correct the identified problems. Also, no specific date for completion of all corrective actions was cited.

O8 Miscellaneous Operations Issues (92700, 92901)

O8.1 (Closed) Licensee Event Report (LER) 50-293/95-004-00: Drywell-to-torus vacuum relief system actuation while de-inerting the drywell

On March 24, 1995, an actuation of the drywell-to-torus vacuum relief system occurred while de-inerting the drywell. At the time of the event, the standby gas treatment system (SBGT) was aligned to vent nitrogen from the drywell. As drywell pressure approached atmospheric, operators attempted to initiate an air purge of the drywell by opening the purge supply valves, AO-5035A/B, and starting the drywell purge fans. A delay in opening AO-5035A (that is, a delay in initiation of the drywell air purge), along with the continued operation of the SBGT, resulted in drywell pressure reaching the 2.0 psid actuation setpoint of the drywell-to-torus vacuum breakers.

The cause of the actuation was determined to be inadequacies in the procedure for de-inerting the drywell. Specifically, the drywell purge supply valve, AO-5035A, has control switches located on two different panels; both switches must be in the OPEN position for the damper to be properly aligned. However, PNPS 2.2.70, Primary Containment Atmospheric Control System, did not identify the location of the dual control switches for AO-5035A. As a result, the switch on panel C-7 was in the OPEN position, but the switch on panel C-904 was in the CLOSED position. This licensee-identified and corrected violation constitutes a **noncited violation**, consistent with Section VII.B.1 of the NRC Enforcement Policy.

In response to this event, the licensee revised PNPS 2.2.70 to specify the locations and positioning requirements for the AO-5035A control switches. The inspector considered the revision to PNPS 2.2.70 appropriate to prevent recurrence. LER 50-293/95-004-00 is closed.

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726, 62707)

Using inspection procedures 61726 and 62707, the inspector observed portions of selected maintenance and surveillance activities to verify proper calibration of test instrumentation, use of approved procedures, performance of the work by qualified personnel, conformance to limiting conditions for operation, and correct system restoration following maintenance and/or testing. The following activities were observed:

- 8.B.1 Fire Pump Test
- 8.A.1 Drywell to Torus Vacuum Breaker Monthly/Quarterly Operability
- 7.3.11 Radioactive Iodine
- 8.4.1 Standby Liquid Control Pump Quarterly Capacity and Flow Rate Test
- 7.4.6 Operation of Canberra Series 90 Multichannel Analyzer
- MR 19601729 Service water pump room fan VEX 104A
- MR 19601775 Megger "B" residual heat removal pump

b. Observations and Findings

All activities were performed by knowledgeable operators and maintenance and instrumentation and controls (I&C) technicians in accordance with approved procedures and maintenance request (MR) work packages. Observed pre-evolution briefings were thorough in that they addressed the scope of work to be performed, outlined expected effects on control room indications, and stressed procedural adherence and frequent communication between the control room and in-plant workers. The inspector verified systems were post-work tested, where applicable, and returned to their normal configurations. During the fire pump test, the inspector verified that the electric driven fire pump was appropriately declared inoperable after it failed to meet the 10 minute run acceptance criteria. During another activity, the WIN (work it now) team leader provided extensive oversight of the corrective maintenance to replace two broken fan belts on fan VEX-104A.

The inspector observed operations personnel restore a 4160 volt safety related breaker (A603 - "B" RHR pump) back to service following an insulation resistance test. A reactor operator made several attempts to rack breaker A603 back into the switchgear. Proper electrical precautions were observed including wearing a full set of protective clothing and stationing an additional operator as a safety watch. Difficulty was experienced when one charging test switch box had a broken electrical receptacle pin and subsequently when the charging motor receptacle was also broken. As a result, the operator had to manually rack in the breaker using procedure 2.2.6, 4160 VAC System. The inspector noted that operators had to work around the faulty test switch box and charging motor connectors. This indicated the need for increased preventive and corrective maintenance on the electrical hardware needed to automatically rack in 4160 volt breakers.

c. Conclusions

Knowledgeable operators and maintenance and instrumentation and control technicians performed observed surveillance and maintenance activities in a controlled and professional manner, utilizing approved procedures and work packages. For example, the WIN team leader provided effective oversight of the corrective maintenance to replace two broken belts on service water room ventilation fan VEX-104A. Operators had to manually rack a 4160 volt breaker (A603), designed to be automatically racking, into service due to deficient test box racking switch and racking motor connections. Operators took the prescribed electrical precautions by wearing a full set of electrical protective clothing.

M5 Maintenance Staff Training and Qualification (62707)

M5.1 Work Control Process Procedure Training

The inspector attended procedure 1.5.20, Work Control Process, training performed by the work control department to keep the nuclear organization current on the procedure and clarify how the work control process should work. The work control process training was a positive work control department initiative to update the nuclear organization on several changes made to the process since it was first adopted in 1995. After the training, BECo personnel were given an open book quiz on the material to verify that the concepts taught were understood.

M7 Quality Assurance in Maintenance Activities

M7.1 Receipt and Inspection

a. Inspection Scope (62707, 92903)

On August 10, 1996, safety related work on the "A" salt service water (SSW) pump to replace the gib key was placed on hold when a new maintenance supervisor identified that the gib key specifications had a slightly unsatisfactory height dimension. The gib key is the locking mechanism between the SSW pump motor coupling and the pump shaft that transmits the motor torque to the pump. The gib key had been machined by maintenance personnel and accepted by quality control (QC) inspection. The inspector interviewed several personnel including the maintenance supervisor who identified this issue, the QC inspector responsible for verification of the dimensions as part of the receipt and inspection process and others. Further, the related material R&I report (MRIR), MRIR 96-9522, and BECo commercial grade item (CGI) engineering evaluation no. 560 were reviewed. The R&I supervisor initiated problem report (PR) 96.0324 to document and evaluate this issue. As an initiative, the inspector randomly selected several past MRIRs for review.

b. Observations and Findings

The gib key height specification was 0.250 (+0.002, - 0.000) inches. Actual height measurement was 0.256 inches which was 0.004 inches too high. Two additional gib keys of the same lot were remeasured and also found to be slightly in excess of the height specification by 0.001 and 0.002 inches. A digital caliper, which is calibrated to be within 0.001 inch accuracy, was used to take the dimensions. The gib key shank has a slight taper of 1/8 inch every 12 inches. CGI 560 specifies to measure the height of the gib key shank 1/4 inch from the key head. The QC inspector informed the inspector that making such a precision measurement 1/4 inch down on a tapered shaft probably contributed to the height measurement being slightly off. The gib keys were returned to BECo machinists and trimmed down slightly within the prescribed specifications. The inspector noted that PR 96.0324 had an action item to perform a detailed evaluation to determine corrective actions to prevent recurrence. Especially noteworthy was the method of problem identification by the maintenance supervisor who initiated an independent verification of the gib key dimensions as a good maintenance practice prior to installation. The inspector had no further concerns relative to this gib key problem.

The inspector randomly reviewed several other MRIRs and had several questions on one particular MRIR. MRIR 95-0587 for unistrut channel inspections contained a note in the QC inspection remarks concerning the accuracy of the Rockwell hardness tester (HDT-002) machine located in the R&I shop. Note 2 stated the following: "the Rockwell hardness tester is out of calibration for Rockwell scale "B". The Vendor was contacted on February 10, 1995 for possible calibration. Per discussion with the vendor, the calibration blocks appear to be out of calibration and not the tester, new blocks should be ordered. The A scale will not be affected by the questionable B scale." A quality assurance inspector assisted the inspector during the inspection to evaluate the use and accuracy of the hardness tester during 1995. Initially, the measurement and test equipment (M&TE) equipment folder did not contain all calibration data. Shortly later, a M&TE administrative assistant updated the folder. The following chronology was developed:

February 1995 -	MRIR 95-0587 documents calibration problem with HDT-002 on the "B" scale. Vendor contacted and the BECo M&TE calibration block accuracy was questioned by outside vendor.
March 1995 -	Routine annual calibration completed by BECo M&TE successfully for HDT-002 using the BECo M&TE calibration blocks.
May 25, 1995 -	A Request for Services form completed for vendor to calibrate HDT-002.

June 14, 1995- BECo M&TE performs calibration check and finds the "B" channel out of tolerance and initiates a limited use status of HDT-002.

June 21, 1995- Vendor calibrates HDT-002. The ball penetrator holder found mispositioned and also the ball penetrator needed replacement. The BECo calibration block, S/N 87H34072, was tested and found unsatisfactory by the vendor. The calibration report was unclear on whether or not the ball penetrator issues directly affected the AS-FOUND calibration results.

The inspector identified that when the calibration of HDT-002 became suspect as documented in MRIR-0587 in February 1995, the QC inspectors failed to write a problem report or immediately notify the M&TE group for corrective actions in accordance with the MT&E program. Instead, the receipt and inspection group solely relied on verbal advice from an outside vendor over the telephone (contrary to NOP 92A1, "Problem Report Program"). A limited use sticker was not immediately placed on HDT-002 in February 1995 to alert potential users of the calibration problem as intended by the BECo M&TE program. Secondly, the accuracy of the BECo M&TE calibration block, and potentially others, has not been adequately dispositioned to date. Third, an obvious training issue exists that involves the need to periodically inspect the ball penetrator and ensure the ball penetrator holder was installed as designed. Also, weak communications existed between the QA receipt inspectors and the BECo M&TE personnel. (The receipt inspectors were not aware that BECo M&TE personnel conduct annual calibrations of HDT-002.) The BECo M&TE folder for HDT-002 was not maintained up-to-date prior to this inspection. Collectively, these issues represent a condition adverse to quality and were in **violation (VIO 96-06-02)** of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, that requires conditions adverse to quality to be promptly identified and corrected.

The QA department initiated several documents to address the above issues. Deficiency report 96-066 was generated on September 13, 1996 documenting the failure to document a potential problem with the Rockwell Hardness Tester. The report also indicated that a formal corrective action process was not used and appropriate BECo M&TE personnel were not informed back in 1995. PR 96.0369 was generated on September 9, 1996 to fully explore the ramifications of the BECo M&TE calibration block that was found to be unacceptable. Surveillance Report 96-066 was issued on September 18, 1996 providing various qualitative assessments such as the need for training, better interdepartmental communications and better adherence to the M&TE program.

c. Conclusions

The questioning attitude of a new BECo maintenance supervisor identified a deficiency with the dimensions of a service water pump shaft gib key prior to installation. As a result, the work to replace the gib key on the "A" SSW pump was placed on hold. The replacement key had been previously accepted by a QC inspector. As an initiative, the inspector expanded review of this receipt and inspection issue by reviewing several MRIR packages. A condition adverse to quality was identified that involved the Rockwell Hardness Tester machine which exhibited calibration problems that were not promptly identified and corrected. Several peripheral issues also became apparent during this review indicating levels of informality in the receipt and inspection area. This is another example of not adequately resolving a condition adverse to quality (section I.07.1

M8 Miscellaneous Maintenance Issues (92902)

M8.1 <u>(Closed) Unresolved Item 50-293/94-18-04: Core spray keepfill system isolation valve leakage rate criteria</u>

The core spray keepfill system utilizes the condensate transfer system to maintain the low pressure coolant injection system and core spray system discharge piping full of water. Check valves CS-212A and CS-212B isolate the keepfill system from the condensate transfer system upon loss of pressure in the condensate transfer system. The licensee had established a leakage rate limit of 1.0 gallon per minute (gpm) for these isolation check valves based on the acceptance criteria established in American Society of Mechanical Engineers/American National Standards Institute, ASME/ANSI OM Code-1988 Part 10. The inspector questioned whether BECo had considered potential radiological consequences outside secondary containment when establishing the acceptance criteria. BECo generated PR 94.0314 to address this concern.

The inspector reviewed completed PR 94.0314. BECo performed a plant-specific radiological evaluation (calculation number PNPS-1-ERHS-XIII.W-58) assuming keepfill valve leakage outside secondary containment following a design basis loss of coolant accident (LOCA). The evaluation concluded that the limiting parameter due to leakage was thyroid dose to control room personnel. The allowable leakage rate for the keepfill isolation valves therefore varied with the assumed halogen removal efficiency of the control room intake filters. Using the current minimum acceptable removal efficiency of 95 percent, the allowable leakage rate is 0.055 gpm; however, if the removal efficiency is assumed to be 99 percent, the allowable leakage rate is 0.3 gpm. The licensee is evaluating which combination of limits to adopt and will have the new limits in place prior to the next scheduled test.

The inspector reviewed the results of recent keepfill valve leakage rate testing and control room intake filter halogen removal efficiency testing. The highest combined valve leakage in two sets of tests (1993 and 1995) was 0.02 gpm, and the lowest filter efficiency in five sets of tests (from 1989 to 1996) was 99.95 percent. Based on these results, the inspector concluded that the radiological consequences of keepfill valve leakage following a LOCA would have been within acceptable limits despite the non-conservative acceptance criteria that were in use at the time. Given that BECo has completed a radiological evaluation of keepfill system leakage and is tracking the establishment of new acceptance criteria, **UNR 94-18-04** is **closed**.

M8.2 <u>(Closed) LER 50-293/95-001-00: Reactor building-to-torus train "B" vacuum relief system actuation while operating</u>

On January 1, 1995, an operator noted that the control room indicators for valves in the reactor building-to-torus train "B" vacuum relief system (air operated valve AO-5040B and check valve X-212B) were not illuminated. Investigation revealed that AO-5040B was open. Troubleshooting identified the cause to be a loose fuse in the control circuitry for the solenoid valve that controls air to AO-5040B. The affected circuit also provides position indication for AO-5040B and X-212B. The licensee concluded that valve X-212B remained shut throughout the event because a slightly positive relative pressure existed inside the torus, which would have tended to seat the valve. Therefore, the primary containment system barrier was maintained.

Immediate corrective action was to tighten the fuse clip and replace the fuse. The affected fuse was noted to be coated with a layer of oxidation product, which may have contributed to the loss of continuity. Inspection of other fuses in the same panel identified additional fuses that were coated with a layer of oxidation, however, no other loose fuses were found. A maintenance work request was generated to perform a more extensive inspection of all fuses and fuse holders in the panel. Further review identified that the affected fuse had last been replaced using a temporary procedure, and that this procedure did not direct inspection of the fuses or fuse clips prior to reinstallation. The governing procedure for writing temporary procedures, 1.3.4-1.9, Temporary and Special Test Procedures Formatting Guide, did not direct inclusion of such instructions. Procedure 1.3.4-1.9 was subsequently revised to require fuse inspections similar to those already in place in other relevant procedures and writing guides.

The inspector noted that the LER did not specify the length of time that valve AO-5040B had been inoperable. Through discussion with the licensee, it was established that approximately one hour elapsed from the time of discovery until the fuse clip was tightened and reinstalled. Given that X-212B was shut throughout this period, no violation of technical specification requirements occurred. The inspector concluded that the corrective action stated in the LER was appropriate to prevent recurrence. **LER 50-293/95-001-00** is **closed**.

III. ENGINEERING

E2 Engineering Support of Facilities and Equipment

E2.1 Nuclear Fuel Leak Identified

a. Inspection Scope (37551)

During routine reactor water chemistry sampling in late July 1995, an increase in the Iodine (I)-131 (long lived) to I-133 (short lived) ratio was noted. This increase indicates that a fuel cladding defect may be present in the reactor's nuclear fuel. The inspector discussed this finding with chemistry management personnel and reviewed the previous and subsequent reactor water and offgas sample test results. In addition, during deep backshift hours, the inspector observed power suppression testing, which was conducted to identify the leaking fuel, and monitored the offgas sample results following this testing.

b. Observations and Findings

Leaking fuel detection

After the reactor water samples showed an increasing trend, an offgas sample was taken on August 12 and confirmed the increased levels of radioactivity. Problem report (PR) 96.9402 was issued to determine the root cause of the increase in I ratio, determine corrective actions and actions to preclude recurrence.

Per PNPS Technical Specifications (TS), reactor water and offgas limits and sampling frequency are listed in the table below.

	Reactor Water Iodine	Offgas Noble Gas
Applicable TS Section	3.6.B.1	3.8.G.1
TS Limit	< = 20 uCi/ml	< 500,000 uCi/s
TS required sample frequency	1/96 hrs	1/31 days
PNPS normal sample frequency	3 times/week	1/2 weeks
Sample Frequency after 8/12	3 times/week	3 times/week
Sample Frequency after power suppression testing 8/23	daily back to 3x/wk 9/16	daily for 1st wk then 3 times/wk

Although the TS limit for Iodine applies to total Iodine, it is most useful to examine the I-131/I-133 ratio. The larger this ratio, the more significant the fuel leak is. Before a leak was indicated, this ratio was approximately 0.08. After the leak was confirmed in mid-August, this value rose to approximately 0.18. In addition to regularly sampling the reactor water, the chemistry department also takes a sample of the offgas stream downstream of the recombiners twice a month. The offgas values are taken as a sum of radioactivity detected from noble gas isotopes Xe-138, Kr-87, Kr-88, Kr-85m, Xe-135, and Xe-133.

The inspector verified that the total Iodine level in the reactor water and the noble gas level in the offgas remained many orders of magnitude below the TS limits specified in the table (0.011 uCi/ml for I, 8046 uCi/s for noble gases).

Power Suppression Testing

Chemistry and operations support personnel coordinated well with General Electric to evaluate the problem and determine a course of action. BECo decided to perform power suppression testing on August 23 through 26 to determine the location of the degraded cladding. Power was reduced to approximately 60 percent as recommended by General Electric's service information letter (SIL) 397, Power Suppression Testing, Revision 1. During this testing all 145 control rods were moved, one at a time. Offgas activity was recorded after each rod was inserted and then after it was withdrawn. For this testing, a Xe-133 (long lived)/Xe-138 (short lived) was used to gauge the response. A higher ratio indicates where the fuel leak is located. BECo personnel coordinated well with Centec

XXI, a vendor specializing in collecting and analyzing the offgas Xe ratio, during power suppression testing.

The inspector observed portions of the power suppression testing conducted per procedure 9.32, Power Suppression Testing, Revision 1, dated August 22, 1996. The 50.59 safety evaluation performed for the procedure was acceptable to determine that no unreviewed safety questions existed. The pre-evolutionary briefs given in the control room before each shift were thorough, in that they explained the purpose for the testing; reviewed the scope and progression through the procedure; stressed communication flow between reactor engineering, Centec, and control room operators, in addition to local and back panel operators during the first 25 moves which were completed by scram time testing the rods; and reiterated the use of self-checking and taking the time to "do-it-right-the-first-time ". The testing was conducted in a professional manner, with self-checking and effective communication evident.

Power Suppression Results and Current Status

Through the suppression testing, control cell 14-27 was determined to have the highest probability of containing the leaking fuel. BECo discussed the results of the test with General Electric and decided to fully insert (position 00) control rod 14-27. In addition the control rods in two adjacent cells, 10-27 and 18-27, were also fully inserted to suppress the power in the area of the suspect fuel. When a control rod is inserted into its control cell, the nuclear reactions in that cell are suppressed, thereby reducing the power in that cell and providing the leaking fuel rod a degree of protection from further damage.

As shown by the previous table, chemistry increased their sampling frequency following the power suppression testing. Per General Electric, power suppression is considered effective if the offgas levels return to 1000 - 1500 uCi/s above pre-fuel leak levels after steady state operation for 5 to 6 days. Chemistry data has been consistently forwarded to General Electric since the power suppression to monitor the fuel's condition. For PNPS, the acceptable level is approximately 5000 - 5500 uCi/s. Although the plant has not maintained steady 100 percent power operation for this time period since the power suppression testing, the offgas levels thus far indicate that the power suppression was successful.

c. Conclusions

BECo responded promptly to reactor water and offgas indications of leaking nuclear reactor fuel in August 1996. Chemistry personnel quickly identified the indications and communicated them to the organization so that a root cause evaluation and corrective actions could be initiated in a timely manner. Reactor engineering, chemistry, and operations personnel effectively communicated with General Electric and Centec to execute a controlled, well-planned process to identify the leaking fuel cell. Power suppression briefings were thorough and contributed to professional execution of the testing. BECo chemistry and reactor engineering personnel communicated well with General Electric to determine a safe control rod pattern and examine the results of subsequent chemistry data to evaluate the effectiveness of the power suppression.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Update) Unresolved Item 50-293/94-26-01: Diesel Generator Turbo Assist Solenoid Valve Testing

During performance of a routine monthly surveillance test (PNPS 8.9.1) on January 22, 1994, the "B" emergency diesel generator (EDG) failed to start within the maximum allowable time of 10.25 seconds. The cause of the slow start was determined to be that the two turbo assist solenoid valves had failed in the shut position. The valves are arranged in parallel so that failure of one valve will not prevent the turbo assist system from performing its design function, boosting the turbocharger during engine start to reduce start time. In this case, however, both valves had failed. The valve failures were determined to be due to mechanical binding caused by a small amount of dried residue along the piston rings. The valves were cleaned and reinstalled, and the "B" EDG start time was verified to be satisfactory. The licensee initiated PR 94.9033 to track additional corrective action. This event was discussed in NRC inspection report 50-293/94-02.

Prior to this event, the EDG turbo assist solenoid valves had been tested individually on an 18-month cycle, during refueling outages. This frequency had been considered adequate based on the absence of previous failures to satisfy the minimum start time requirement. Although failure of both valves was considered highly unlikely, there was no indication from the parameters that were monitored during monthly testing that a single valve had failed. Based on the January 1994 occurrence, the testing frequency for the individual turbo assist solenoid valves was increased to quarterly. Procedure 3.M.3-61.3, Emergency Diesel Generator Quarterly Preventive Maintenance, was revised to accomplish this testing. In addition, a plant modification (FRN 94-03-07) was developed to install isolation valves in the EDG turbo assist system to allow for on-line testing and replacement of the turbo assist solenoid valves. Installation of this modification was completed in September 1994 and was discussed in inspection report 50-293/94-18. During post-modification acceptance testing, both EDGs were initially slow to start, but achieved satisfactory start times after several starts. This problem was attributed to inadvertent introduction of foreign material during installation of the modification which caused fouling of the solenoid valves.

On December 6, 1994, one of the turbo assist solenoid valves (SV-4570A) for the "A" EDG functioned erratically during the quarterly test (3.M.3-61.3). PR 94.9620 was generated to conduct a root cause analysis to determine the cause of the failure, and to determine corrective actions and actions to preclude recurrence. The event was reviewed in inspection report 50-293/94-26 and was opened as an unresolved item pending completion of the problem report and root cause analysis.

The inspector reviewed completed PR 94.9620. To verify that the failure was not due to a different mechanism than had previously been experienced, BECo had requested the manufacturer to evaluate the condition. No new failure mechanism was identified, and the cause was again determined to be residue along the piston rings. The report cited this as the root cause of the solenoid valve failures; however, it concluded that no action was necessary to preclude recurrence because the increased testing frequency that had been instituted by PR 94.9033 was adequate.

The inspector questioned BECo's response to PR 94.3033. Rather than determining actions to prevent recurrence, the corrective action accepted that valve failures will occur and relied on more frequent testing to provide detection of individual failures and thereby avoid loss of system function due to an undetected sequential failure of both valves. The problem report noted the root cause of the failure as residue along the piston rings; however, the source of the residue was not identified. During discussions on this matter, BECo stated that the cause of the residue had been established to be corrosion products that were the result of moisture in the air start system. By separate evaluation, the licensee had considered the existence of moisture in the EDG air start systems, and determined that action to eliminate the moisture was not required.

The inspector concluded that BECo's response to occurrences of slow EDG start times did not thoroughly and completely addressed the problem. Although the current approach reduces the probability of simultaneous failure of the turbo assist solenoid valves, a real possibility for such a failure remains. The valves operate in an environment that is known to be detrimental and that will inevitably cause malfunction. However, BECo is relying on detection of valve failure (through frequent testing) to avoid loss of system function, rather than prevention of failure. BECo reported that individual solenoid valve failures have been identified on two occasions since the increased testing frequency was adopted. This item remains unresolved pending accumulation of additional data for trending and evaluation. On August 19, 1996, BECo initiated problem report 96.9413, significance level 2, to review this issue further.

IV. PLANT SUPPORT

P3 EP Procedures and Documentation

P3.1 Emergency Procedures Revision and Training

a. Inspection Scope (71750, 82301)

The inspector witnessed training for changes of various emergency procedures affecting the operations support center (OSC). The inspector attended one of the training sessions and then observed an activation drill, conducted on September 12 using the new procedures, to assess BECo's approach to OSC organizational assessment and resultant procedure revisions in the emergency preparedness area.

b. Observations and Findings

BECo recognized that in the past several years issues were raised concerning the ability of the OSC to dispatch, track and prioritize team activities. Instead of continuing to correct specific problems as they were identified, BECo decided to take a more holistic approach to assess the functions and conduct of operations within the facility. During this assessment specific changes were identified including; reorganization of the OSC reporting structure, simplification of the documentation process used for OSC team dispatch, and development of procedural guidance for the prioritization and tracking of OSC team activities.

The table-top discussion the inspector observed was attended by various members of the emergency response organization including radiological protection, engineering, and emergency preparedness personnel. The discussion was conducted to familiarize emergency response organization personnel with the changes to the procedures, validate the procedures, and provide a forum for comments and suggestions. The discussion leader provided a good background discussion on the purpose of the revisions and then talked through the procedures with the attendants. The inspector noted eager participation in the discussion and willingness to ask for clarifications and provide feedback. As a result of this and the other discussions held, the draft procedures were further revised.

Subsequently, on September 12, 1996, BECo conducted an emergency preparedness activation drill to test the mobilization of the emergency response organization and practice activation of the emergency response facilities. During this drill the draft procedures for the OSC were used. When some of the drill participants were not initially aware that the draft procedures were to be used, the controllers explained which revision to use and explained the purpose. Although the drill was an activation drill, the participants in the OSC who were involved in team dispatch activities continued the drill even after the activation portion was completed to enable a real test of the procedures to be conducted. After the drill was ended, the drill participants were asked for further feedback on the draft procedures.

c. Conclusions

The decision to take a broad look at problems identified with operations support center (OSC) ability to dispatch, track, and prioritize teams was positive. Emergency preparedness personnel trained emergency response personnel on draft procedure revisions to obtain feedback to make the procedures clearer and more useful and effective. In addition, the procedures were aggressively validated during an activation drill in which they were used.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Temporary Repair to Diesel Fire Pump Exhaust Manifold

On August 9, 1996, during the performance of 8.B.1, Fire Pump Test, operators discovered a pinhole leak in the diesel fire pump exhaust manifold. Operators promptly declared the diesel fire pump inoperable and entered an LCO. PNPS Updated Final Safety Analysis Report (UFSAR) Section 10.8.4.2.1, Fire Water Supply System Technical Requirements, states, "...if [either the electric or diesel driven fire pump] is inoperable, the [inoperable pump] should be returned to service within 7 days or implement the plans and procedures to be used for the loss of redundancy in the system."

A new exhaust manifold was ordered but was not scheduled to be delivered within 7 days. BECo then issued MR 19601723 to weld repair the pinhole leak. This method was discussed with the vendor, Cummins, who stated that this repair would allow BECo to return the pump to service indefinitely. The repair was completed and post work tested on August 26. Since this repair was not completed prior to the 7 day LCO allowed outage time, the inspector verified that procedure 2.4.54, Loss of All Fire Suppression Pumps or Loss of Redundancy in the Fire Water Supply System, was entered. The inspector observed the performance of 8.B.1 in September and confirmed that the manifold was not leaking and the weld repair was successful.

After a leak was discovered in the water jacket of the diesel fire pump, BECo personnel declared the pump inoperable and entered the appropriate FSAR LCO action statement. The inspector considered BECo's actions to perform a temporary weld repair to the manifold, instead of remaining in the loss of redundancy procedure until the replacement part could be obtained, evidence of a strong commitment to plant material condition.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on October 23, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X4 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for additional verification that licensees were complying with Updated Final Safety Analysis Report (UFSAR) commitments. For an indeterminate time period, all reactor inspections will provide additional attention to UFSAR commitments and their incorporation into plant practices and procedures. While performing inspections discussed in this report, inspectors reviewed the applicable portions of the UFSAR. No inconsistencies were noted.

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 82301:	Evaluation of Exercises for Power Reactors
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901:	Followup - Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENEᴅ, ᑦLOSED, AND UPDATED

<u>Opened</u>

IFI 50-293/96-06-01	Adequacy of root cause analysis for "B" RBCCW heat exchanger through-wall leak
VIO 50-293/96-06-02	Corrective action process and organization not effective in identifying and/or correcting overall procedural adherence and adequacy problems at Pilgrim

<u>Closed</u>

IFI 50-293/96-03-01	Operator training issues related to the April 19, 1996 automatic scram and subsequent start-up
UNR 50-293/96-80-03	Performance concern with proper procedural use
LER 50-293/95-004	Drywell-to-torus vacuum relief system actuation while de-inerting the drywell
UNR 50-293/94-18-04	Core spray keepfill system isolation valve leakage rate criteria
LER 50-293/95-001	Reactor building-to-torus train "B" vacuum relief system actuation while operating

<u>Updated</u>

UNR 50-293/94-26-01	Diesel Generator Turbo Assist Solenoid Valve Testing

LIST OF ACRONYMS USED

ALARA	As Low As Is Reasonably Achievable
APRMs	Average Power Range Monitors
BECo	Boston Edison Company
CFR	Code of Federal Regulations
CRD	Control Rod Drive
CS	Core Spray
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
EPIC	Emergency and Plant Information Computer
ESF	Engineered Safety Feature
gpm	gallons per minute
I&C	Instrumentation and Controls
IFI	Inspection Follow-Up Item
IR	Inspection Report
LCO	Limiting Condition For Operation
LER	Licensee Event Report
MG	Motor Generator
MR	Maintenance Request
MRIR	Maintenance Receipt and Inspection Report
NCV	Non-Cited Violation
NOS	Nuclear Operating Supervisor
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NWE	Nuclear Watch Engineer
PNPS	Pilgrim Nuclear Power Station
PR	Problem Report
PSU	Plant Status Update
QA	Quality Assurance
QC	Quality Control
RBCCW	Reactor Building Closed Cooling Water
RHR	Residual Heat Removal
RO	Reactor Operator
RP	Radiological Protection
SALP	Systematic Assessment of Licensee Performance
SRO	Senior Reactor Operator
SSW	Salt Service Water
TM	Temporary Modification
TS	Technical Specification
UNR	Unresolved Item
UFSAR	Updated Final Safety Analysis Report
WWM	Work Week Manager