Enclosure 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

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Report No.	96-08
Docket No.	50-293
Licensee:	Boston Edison Company 800 Boylston Street Boston, Massachusetts 02199
Facility:	Pilgrim Nuclear Power Station
Inspection Period:	September 24, 1996 - November 22, 1996
Inspectors:	R. Laura, Senior Resident Inspector B. Korona, Resident Inspector L. Peluso, Radiation Physicist, DRS
Approved by:	R. Conte, Chief Reactor Projects Branch No. 5 Division of Reactor Projects

EXECUTIVE SUMMARY

Pilgrim Nuclear Power Station
NRC Inspection Report 50-293/96-08

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers resident inspection for the period of September 24 through November 22, 1996. This report also includes the results of announced inspections of the radioactive effluent controls program, conducted September 30 through October 4, and radiological environmental monitoring and meteorological monitoring programs, conducted October 15-18, 1996. Both of these inspections were conducted by regional radiation specialist Ms. L. Peluso.

Operations: Three minor equipment issues and an incorrectly positioned salt service water thermowell cover were observed during plant tours. These items were discussed with the nuclear watch engineer and system engineer and were properly resolved. Professional response to a control room alarm was observed during a pre-evolution brief for an unrelated system. NSRAC members provided important feedback and asked probing questions during various BECo staff presentations on November 20th. (Section I.O1.1)

Operators returned the unit back to full power operations in a professional manner following the unplanned outage to repair the "B" RBCCW heat exchanger. The PEB for startup and power ascension emphasized past lessons learned, encouraged proper procedural usage and self verification techniques, and was attended by operations department management. Excellent equipment problem identification and resolution was observed that involved a small steam leak inside containment identified by operators, several half scram conditions due to a leaking scram outlet valve and a recirculation pump seal alarm. (Section I.O4.1)

Operators promptly identified feedwater flow and resultant reactor vessel water level oscillations during a routine downpower on October 26. Operators gained control of the transient by placing feedwater control in manual and determined the cause was a leak on the "B" feedwater regulating valve. Later, operators "locked up" the valve in accordance with an approved procedure to prevent it from failing full open. Operators were fully trained in the simulator on a temporary procedure developed for the power reduction and post work test for the FRV. This action resulted in an improved temporary procedure and positive operator performance during the November 8 downpower. (Section I.O2.1)

Maintenance: I&C technicians communicated effectively with control room operators during a procedure which automatically started the "A" core spray pump. This additional communication was not required per procedure, but served to ensure that operators were following the correct procedure as two were covered at the pre-evolutionary briefing. Thorough engineering coverage of the "E" salt service water full flow test was observed. After the pump failed the full flow test, confirming previously failed shutoff head tests for operability, the pump was rebuilt before it was returned to service. (Section II.M1.1)

The repair to the "B" FRV was well prepared and executed. Extensive mock-up training of all involved maintenance supervisors and technicians allowed a well written procedure and MR to be developed. In addition, the training served to familiarize the workers with the task

so they could quickly detect potential disassembly problems during the on-line repair. Round-the-clock engineering support aided in the understanding of encountered problems and development of solutions. Management's decision to postpone the repair to the "B" FRV actuator until the week of November 8 was focused on safety. It allowed additional simulator and mock-up training for operators and maintenance personnel involved which resulted in a professional and well controlled corrective maintenance activity. (Section II.M2.1)

A careful and thorough Code repair was made to the "B" RBCCW heat exchanger channel head. The original through-wall leak and other cracks were excavated and weld repaired in a meticulous manner. Appropriate control of the corrective maintenance was evident, and the work was well supported by engineering and quality assurance personnel. (Section II.M2.2)

Electricians were observed using an incorrect electrical crimping tool during replacement of the motor actuator on MO-1301-48. The electricians obtained the correct tool and reworked previously installed electrical connections. Using the incorrect tool resulted from not utilizing the procedural instructions. Because of BECo's long-term corrective actions in progress concerning procedures, this issue is considered a **noncited violation**. However, several days later just prior to plant restart, the same electricians competently replaced a 480 volt electrical supply breaker for the "D" SSW pump as a Priority 1 activity which emerged just prior to plant restart. (Section II.M4.1)

Extensive RFO11 preparations were underway including several initiatives to improve overall outage coordination and execution. The planned use of contractor fuel handlers under the direction of BECo SROs demonstrated a substantial commitment to reduce the burden on the operations department during the outage. A computer-based risk model was being developed to produce a shutdown risk curve, for the first time, over the outage duration. Two emergent items involving increased drywell radiation levels and the ECCS suction strainer modification have the potential to impact the established outage scope. (Section II.M6.1)

LERs 94-05 and 94-05 Supplement 1, provided a complete description of the August 1994 reactor scram and developed root causes. The inspector noted a long time delay in the issuance of the supplement due to higher work priorities. Root cause evaluations performed after a 1993 damper closure failure and the 1994 secondary containment damper failures during the subject scram were not complete. Although the corrective actions planned for the 1994 failures were broad enough to have found the root cause, it wasn't until a 1995 evaluation of an additional damper failure to fully close that the bonafide root cause was discovered. Since appropriate corrective actions for the damper failures had been identified after the 1994 event and were subsequently performed after the 1995 event, **Licensee Event Report 94-05 and its supplement are closed**. (Section II.M8.1)

VIO EA95-10, which related to a degraded primary containment boundary due to a failure to follow a calibration procedure was **closed**. (Section II.M8.2)

Engineering: Blackness testing of a Boraflex spent fuel pool storage rack was conducted using a temporary procedure developed by BECo with vendor input. The initial pre-evolutionary briefing was thorough and discussed background information, test method, effect on control room operators, and abort criteria. Thorough ORC review of the operability evaluation for the preliminary test results determined that a 50.59 safety evaluation was required to disposition the observed Boraflex degradation. An appropriate review was subsequently performed and determined no unreviewed safety question existed. A weakness was noted in the safety evaluation process, which led to the improper determination that a safety evaluation was not originally needed. This area will remain unresolved pending future BECo and NRC staff review as (**Unresolved Item (URI) 96-08-01**), (Section III.E1.1).

A finite element analysis was performed by a vendor to determine the acceptability of the "B" RBCCW heat exchanger following the Code repair. The results of this analysis were appropriately used to validate assumptions made in the root cause analysis and operability evaluation. BECo maintained proper oversight of vendor services as evidenced by BECo identification of an incorrect partition plate thickness value used in the original fatigue analysis for the failed "B" RBCCW heat exchanger. After a history of repairs and modifications of the original design for the RBCCW and TBCCW heat exchanger partition plates, BECo had initiated a design change to the plates and channels. However, these planned modifications were not timely enough to preclude the September 1996 shutdown after a through-wall leak was discovered in the "B" RBCCW heat exchanger channel. BECo's plan to upgrade and replace the channels in all four heat exchangers during the February 1997 outage is appropriate. **IFI 96-06-01 is closed.** (Section III.E2.1)

A brief loss of shutdown cooling occurred on September 25, 1996 due to an inadequate procedure used to backfill reference legs for nonsafety-related condensing chambers 13A and 13B. An incomplete modification plant impact review resulted in the procedural deficiency. In an unrelated matter, I&C had to rework the SRM discriminator settings due to a procedural adherence issue involving a system engineer. Both issues were treated as **non-cited violations** due to self identification and prompt corrective actions. Increased reliability of the SRM/IRMs was observed during plant startup which was an improvement over the previous startup.

Engineering personnel conducted methodical diagnostic testing and completed related corrective maintenance including replacement of 2 IRM detectors and implementing an innovative design change for detector connectors. (Section III.E2.2)

An initiative to review the UFSAR to determine whether PNPS was operating within the scope of the PNPS UFSAR was focused on safety-related and risk significant systems. The initial BECo results identified no significant problems involving operability. (Section III.E7.1)

Plant Support

An overall effective Radioactive Effluent Control Program (RECP) was observed including management controls, quality assurance audits, radioactive liquid and gaseous effluent controls, calibration of effluent/process radiation monitoring systems (RMS), and air cleaning systems. The Offsite Dose Calculation Manual (ODCM) was properly implemented. Audits were effective in assessing program strengths and weaknesses. No deficiencies in the Updated Final Safety Analysis Report commitments had been identified. One **Violation (VIO 96-08-02)** of technical specifications requirements was identified. The violation was related to not performing the required sample and analytical requirements of the neutralizing sump. (Sections IV.R1.1, R1.2, R1.3, R6.1, R6.2, R7.1)

An overall effective radiological environmental monitoring program (REMP) was observed including management controls, quality assurance audits, radiological environmental monitoring, and meteorological monitoring program. The Offsite Dose Calculation Manual (ODCM) was properly implemented. Audits were effective in assessing program strengths and weaknesses. No deficiencies in the Updated Final Safety Analysis Report commitments were identified. (Sections IV.R1.4, R1.5, R6.3, R7.2, R7.3)

The 1996 emergency preparedness exercise was conducted well. Observed response organization actions in the OSC and TSC were appropriate and in accordance with emergency implementing procedures. The Emergency Plant Manager and OSC Supervisor conducted timely briefings to update OSC and TSC personnel on plant conditions, emergency declarations, and task priorities and status. Good communication between the Radiological Protection Coordinator in the OSC and the Radiological Supervisor in the TSC aided timely dispatch of OSC field teams. The exercise critique was thorough and addressed both positive and negative aspects of emergency response organization performance during the drill. (Section IV.P1.1)

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REPORT DETAILS

Summary of Plant Status

Pilgrim Nuclear Power Station (PNPS) was shutdown at the beginning of the period to facilitate repairs to the "B" reactor building closed cooling water (RBCCW) heat exchanger. Operators performed the shutdown on September 18. On September 29 at 2140 hours, after repairs to the heat exchanger were completed, operators returned the unit to power. 100 percent rated core thermal power was achieved on October 3 at 0139 hours. Operators reduced power to approximately 80 percent to perform a control rod pattern change. Full power was restored on October 5.

Operators maintained the reactor at approximately 100 percent power, with the exception of reducing power to approximately 90 percent over the weekends for scheduled control rod exercises. On October 19, at 0200, a power reduction to 50 percent commenced to perform a backwash of the main condenser. Operators returned power to 100 percent at 2230 hours that evening. On October 26, operators reduced reactor power to approximately 90 percent to perform scheduled control rod exercising. Full power was achieved later that evening where it remained until November 8.

On November 8 operators commenced a reactor downpower to approximately 50 percent to perform a main condenser backwash and corrective maintenance on the "B" feedwater regulating valve which had oscillated during the power reduction on October 26. (See Sections I.O2.1 and II.M2.1 for details on the "B" feedwater regulating valve downpower and maintenance.) Operators returned power to approximately 100 percent on November 18 where power was maintained through the end of the report 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 inspectors discussed any observed alarms with the operators and verified that they were aware of any lit alarms and the reasons for them. The inspector observed that a longstanding control room deficiency on a residual heat removal (RHR) system digital total flow indicator was repaired during this period.

Three minor equipment issues observed during plant tours were discussed with the NWE and system engineer for resolution. Two straps were observed broken that secured a flexible fire detection sampling hose located directly above the reactor core isolation cooling

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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.

(RCIC) turbine. The inspector expressed concern that the loose hose could possibly interfere with the RCIC turbine control linkages. The two broken straps were replaced, properly securing the hose. Also, the inspector questioned why a large piece of lagging, inner and outer pieces, on the high pressure coolant injection (HPCI) turbine were removed. The inspector was concerned that without the lagging installed, increased temperatures from the HPCI turbine could possibly affect the controls in a nearby electrical control box. The system engineer explained that during the last surveillance run, the lagging was removed in search of a possible leak. A leak was not found. The system engineer reminded maintenance workers to re-install the lagging which was verified to be complete by the inspector several days later. Lastly, an oil drip pan for the "B" emergency diesel generator (EDG) fuel oil transfer pump was not properly aligned and allowed a small amount of fuel oil to leak on the floor.

During a tour of the auxiliary bay, the inspector reviewed the instructions on a caution tag hanging on the cover of a leaking thermowell. The cover was previously removed to prevent water intrusion into the related conduit and to monitor the leak rate. The caution tag specified to keep the thermowell cover threaded off. However, the inspector noted that the thermowell cover was threaded on. The inspector expressed concern to a system engineer who toured the area and confirmed the cover was threaded on, which was opposite of the condition specified by the caution tag. The cover was returned to its caution-tagged position, off, and PR96.9580 was written to determine why the cover had been re-installed. When the cover was removed, no significant leakage was observed and the inspector did not have a concern about water migration into the conduit. On subsequent tours, the inspector verified the cover remained off. At the exit meeting, plant management stated that the cause was not known but was still under review. The inspector determined that this problem was related to plant workers not following the caution tag instructions.

During a pre-evolutionary brief (PEB) for a salt service water (SSW) surveillance, an alarm actuated in the control room for the RCIC system. The inspector observed professional alarm response by the control room operators. The PEB was immediately terminated and extra personnel were cleared from the control room. The reactor operator verified that the RCIC system did not initiate and no RCIC valves changed position. The RCIC alarm was determined to be spurious in nature. Operators followed Alarm Response Procedures and called the alarm panel system engineer. No additional activities were begun until the problem was investigated and understood by the operators.

The inspector attended the Nuclear Safety Review and Audit Committee (NSRAC) meeting held on November 20, 1996. A quorum was assembled of the required division of onsite and offsite personnel. NSRAC members provided important feedback during the various presentations and asked probing questions about other activities at the plant. Other specific events and noteworthy observations are detailed in the following sections.

O2 Operational Status of Facilities and Equipment

O2.1 "B" Feedwater Regulating Valve Oscillations

a. Inspection Scope (71707)

On October 26, while reducing power to 90 percent for a routine control rod exercise, operators noticed feedwater flow and reactor water level oscillations. The inspector reviewed the immediate and subsequent actions taken to compensate for and correct the condition.

b. Observations and Findings

When operators noted oscillations in feedwater flow and reactor vessel level, they took manual control of feedwater. After feedwater level control was placed in master auto with individual manual control on the "B" feedwater regulating valve (FRV), FV-642B, and individual auto control on the "A" FRV, the oscillations were reduced. Boston Edison Company (BECo) personnel entered the condenser bay and discovered an air leak, which indicated damage on the "B" FRV actuator diaphragm. Operators locked up the "B" FRV, in accordance with procedure 3.M.2-10, Feedwater Control Valve Isolation and Maintenance, by reducing air to the actuator and following the valve stem with the handwheel to prevent the valve from going full open. The inspector noted that operators verified they could close the valve from the control room before power was returned to 100 percent.

Operations management issued Standing Order 96-07 on October 26 to direct operators to leave the FRV in the locked position and to review FRV failure actions and feedwater level control following a scram. The inspector observed these briefings during the shiftly briefs. Operators were aware of the problems on the actuator and actions to take during an event. During operation with the "B" FRV in manual, the inspector verified steady feedwater control was maintained. No manual operator action was required during this time.

Temporary Procedure (TP) 96-40, FV-642B On-Line Maintenance, was created to control the November 8 downpower to approximately 50 percent to facilitate the on-line disassembly, repair, and post work testing (PWT) of the FRV. Further detail on this evolution is provided in Section II.M2.1 of this report. The temporary procedure was required to allow operation at 50 percent, within the design control capability of one FRV, since normal operating procedure required power to be lowered to 30 percent before operation with one FRV. Operators were trained on the simulator for this downpower and PWT using TP 96-40. Instrumentation and Controls (I&C) technicians also trained on the simulator and provided feedback to the operators on possible feedwater response during the evolution. Through these simulator sessions revisions were made to improve the TP.

During the November 8 downpower to 50 percent and November 10 post work testing, operators properly followed TP 94-40 and restored the "B" FRV to automatic operation.

c. Conclusions

Subsequently, operators promptly identified feedwater flow and resultant reactor vessel water level oscillations during a routine downpower on October 26. Operators gained control of the transient by placing feedwater control in manual and determined the cause was a leak on the "B" feedwater regulating valve. Later, operators "locked up" the valve in accordance with an approved procedure to prevent it from failing full open. Operators were fully trained in the simulator on a temporary procedure developed for the power reduction and post work test for the FRV. This action resulted in an improved temporary procedure and positive operator performance during the November 8 downpower.

O4 Operator Knowledge and Performance

O4.1 Control of Start-up and Power Ascension Activities

a. Inspection Scope (71707)

After completion of the repairs to the "B" RBCCW heat exchanger on September 29, 1996, the inspector witnessed portions of the approach to criticality, heat-up and power ascension activities during deep back shift inspection. Earlier in the year, the return to power following an April 19, 1996 automatic reactor scram was adversely impacted by nuclear instrumentation and chart recorder problems, as documented in NRC Inspection Report 50-293/96-03, Section I.O1.3.

b. Observations and Findings

At the startup PEB conducted by the NWE, the concepts of self-verification, procedure adherence and strict compliance with the control rod pull sheet were stressed. The operations department manager attended the PEB and reminded the operators to closely monitor power levels in the source and intermediate ranges. Operators turned the mode switch to the STARTUP position at 5:53 p.m. on September 29, 1996, and brought the reactor critical at 9:43 p.m. by withdrawing control rods. The approach to criticality was slow and methodical. Formal communications and control room access were observed throughout the startup and power ascension activities. Operators ranged-up the intermediate range monitor (IRM) instrumentation with increasing power levels with no nuclear instrumentation (NI) problems experienced. This was a significant improvement over the last startup from the April 19, 1996 automatic scram. Further details on maintenance troubleshooting and corrective maintenance performed on the NI systems during this unplanned outage are discussed in Section III.E2.2 of this report.

As power ascension continued, operators changed the mode switch to the RUN position. During the drywell close-out inspection done at pressure, an operator identified steam leakage, with an approximate 6 inch plume, from the packing gland of manual operated valve 1-HO-220B, a gage isolation valve located between the "B" inboard and outboard main steam isolation valves (MSIVs). 1-HO-220B is a normally closed valve indicating that the packing leak resulted from debris on the seating surface. The line downstream of 1-HO-220B had a cap installed. Initial attempts to adjust the packing gland and cycle the valve to stop the leakage were unsuccessful. As a result, the operators exited the drywell. Management directed the control room operators to lower reactor power and change the

mode switch position back to the STARTUP position. This action was taken to reset the 24 hour technical specification (TS) clock to inert the drywell per TS 3.7.A.1.J. The plant staff evaluated repair plans including the consideration of temporary leak repair methods. During a subsequent inspection of 1-HO-220B, the packing leakage stopped when the valve was cycled again. The power ascension recommenced and the operators subsequently changed the mode switch back to the RUN position. The inspector determined that operators performed well by identifying a steam leak inside the drywell, developing contingencies and ultimately stopping the valve leakage.

Operators promptly responded to several equipment problems and/or control room alarms. For example, several half scram conditions resulted from the scram discharge instrument volume (SDIV) high level. The SDIV water levels were not high; however, water leakage from hydraulic control unit (HCU) 02-31 scram outlet valve leaked into the SDIV causing the bimetallic temperature detector (which is a diverse SDIV water level switch) to sense a change in temperature and spuriously actuate. The maintenance staff adjusted the scram outlet valve stem which stopped the water trickling into the SDIV across the temperature sensor. Problem Report (PR) 96.9504 was issued to further evaluate the root cause since this scram valve was worked during the unplanned outage. The maintenance staff intended to review the adequacy of the work package instructions as part of a maintenance rework analysis. Also, operators responded to alarm C904 RC-E6, "A" recirculation pump seal staging low flow. Operators determined, and the inspector independently verified, that the seal temperatures and drywell floor leakage rates trended normally. Operators followed the alarm response procedure actions. No immediate degradation of the seal was evident but increased monitoring and trending was initiated. Operators responded promptly, and followed alarm response and abnormal procedures where appropriate, to equipment issues during the startup and power ascension. A soft startup rate (i.e., 0.11 (KW/ft)/hr which is approximately 1 to 1.5 percent power per hour) was enforced due to a limiting rod pattern with three rods fully inserted to protect a leaking fuel bundle previously discussed in NRC Inspection Report 50-293/96-06. Full power was achieved on October 3, 1996 at 1:39 a.m.

c. <u>Conclusions</u>

Operators returned the unit back to full power operations in a professional manner following the unplanned outage to repair the "B" RBCCW heat exchanger. The PEB for startup and power ascension emphasized past lessons learned, encouraged proper procedural usage and self verification techniques, and was attended by operations department management. Excellent equipment problem identification and resolution was observed that involved a small steam leak inside containment identified by operators, several half scram conditions due to a leaking scram outlet valve and a recirculation pump seal alarm.

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:

- 9.5.1 — Operation of TIP Machines for Process Computer Updating
- 8.M.2-3.1 — Rod Block Monitor Functional Test
- 8.M.2-2.10.1-5 — Core Spray System "B" Logic Functional Test
- 8.5.3.2.1 ATT1E — Salt Service Water System Pump and Valve Operability Tests with Full Flow Test Conditions
- 8.M.2-2.10.1-6 — Automatic Start Core Spray Pump P-215A Logic System Functional Test
- 9.9 — Control Rod Scram Insertion Time Evaluation

b. Observations and Findings

All activities were performed by knowledgeable operators and maintenance and I&C technicians in accordance with approved procedures and maintenance request (MR) work packages. Observed PEBs 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.

The inspector noted excellent communication between I&C technicians and operators during the performance of 8.M.2-2.10.1-6. I&C technicians advised operators to expect alarms generated by the procedure before the steps were taken to initiate the alarms. The procedure required only verification of the alarms. Although this advanced notice was not required by the procedure, it proved to be useful in that it ensured operations was following the correct procedure. Two procedures for the core spray system were briefed during the PEB and the reactor operator incorrectly recalled the wrong procedure was to be done first. The I&C advanced announcement also aided operators in following along with the surveillance. I&C personnel were careful to announce a step where potential to inadvertently remove power from the main stack was possible. This step was explicitly covered by a thorough pre-evolutionary briefing.

Procedure 8.5.3.2.1 was recently approved by ORC to perform a full flow test of salt service water pumps, using ultrasonic flow instrumentation. This procedure verifies pump operability based on flow conditions. Previously, this determination was made using a pump shutoff head test, procedure 8.5.3.2. The "E" SSW pump had recently failed 8.5.3.2

on low shutoff head. In discussing the pump status with the system engineer, the inspector learned that after the pump failed the inservice test (IST) requirement for shutoff head, the pump must either be evaluated or rebuilt. Since the flow test had been run many times before as a temporary procedure, and had recently been approved by ORC, it was decided to run the test to get more definitive data on the pump's condition. The inspector noted that the test was observed locally by the system engineer, IST engineer, and an I&C engineering supervisor. The "E" SSW pump failed the flow test and was subsequently rebuilt and returned to service.

c. Conclusions

Knowledgeable operators and maintenance and I&C technicians performed observed surveillance and maintenance activities in a controlled and professional manner, utilizing approved procedures and work packages. Thorough pre-evolutionary briefs were performed before each activity and appropriate communication was maintained. Equipment was satisfactorily post-work tested and returned to normal configuration following maintenance and testing activities.

I&C technicians communicated effectively with control room operators during a procedure which automatically started the "A" core spray pump. This additional communication was not required per procedure, but served to ensure that operators were following the correct procedure as two were covered at the pre-evolutionary briefing. Thorough engineering coverage of the "E" salt service water full flow test was observed. After the pump failed the full flow test, confirming previously failed shutoff head tests for operability, the pump was not declared operable and was rebuilt before it was returned to service.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 "B" Feedwater Regulating Valve Corrective Maintenance

a. Inspection Scope (62707)

As discussed in Section I.O2.1, an air leak was discovered on the "B" Feedwater Regulating Valve, FV-642B, on October 26. BECo plant management decided to conduct an on-line repair of the valve's actuator. The inspector observed the development of the associated temporary procedure, the mock-up training given to all involved maintenance personnel, and portions of the repair to the valve actuator during deep backshift hours on November 9, 1996.

b. Observations and Findings

After the discovery of the air leak on the "B" FRV actuator on October 26, BECo management decided to perform an on-line repair. The repair was originally scheduled for the following weekend, November 1. Management postponed the repair until November 8 to allow further simulator and mock-up training for the personnel involved and further review of and enhancement to the temporary procedure and work package.

TP 96-40 was developed to control the power reduction and restoration post-work testing (PWT) of the FRV. The procedure was well written and included contingency plans for potential problems, including separate PWT attachments to the procedure depending upon whether the valve was able to be fully closed before maintenance. The procedure delineated the process for aligning the plant to be controlled at 50 percent power with the "A" FRV alone. After this portion was complete, the procedure directed maintenance be performed per the developed work instruction. After the corrective maintenance was performed, the procedure then designated the appropriate PWT to be used. The inspector observed the Operations Review Committee (ORC) meeting where the procedure was originally reviewed. ORC members were thorough in their review and had changes made to the procedure before approval.

The inspector observed one of the several mock-up training sessions conducted for the maintenance supervisors and technicians. All involved supervisors and technicians received this training during the two-week period before the downpower. A spare FRV was retrieved from the warehouse and mounted in the maintenance shop at approximately the same height as it was located in the condenser bay. Technicians worked on scaffolding during the mockup training and used gloves. The inspector noted that the system engineer attended the training and radiological technicians also observed portions of the training to become familiar with the task. The MR work instruction, MR19602400, was revised several times throughout the training sessions as maintenance personnel and engineers devised better methods for performing the task. The mock-up also enabled all of the correct tools for the job to be identified and used for the actual disassembly. Engineering personnel extensively supported the procedure and MR development and helped design a method to fill the actuator with glycol in the plant. These actuators are typically filled in a shop with a horizontal orientation; the valve is installed vertically in the plant.

Pilgrim's FRVs, designed by Copes-Vulcan, are air operated valves which use glycol fill between two diaphragms to dampen oscillations on the valve when it is moved. The nonsafety-related valves are air-to-close and spring-to-open. They are fail open valves. BECo's FRVs are a similar design to Vermont Yankee's. In December 1995, VY experienced a reactor scram when a gagging device in one of their FRVs vibrated loose. BECo personnel communicated with the vendor and Vermont Yankee to ensure the same problem would be avoided. During the training, gagging devices were used for both possible contingencies for closing the valve. In one case, if the valve was determined to be fully closed, two metal blocks were inserted into the actuator bail to ensure that the spring force would not open the valve as it was being worked. The gags were bolted together to ensure they would not vibrate out of position. If the valve could not be fully closed, an addition to the gagging device was made to prevent the valve from going closed.

Prior to the work, the maintenance department manager thoroughly briefed involved maintenance technicians and supervisors. The brief stressed working in a controlled manner, maintaining exposure ALARA, and stopping if there was a problem with the procedure or if unexpected conditions were present. He conveyed that there was no time pressure for the job and if a shut down was needed to perform the job in a quality manner, it would be done. The brief also stressed caution not to affect the operation of the nearby "A" FRV. The "B" FRV was known to have a packing leak. As such, the brief informed the maintenance personnel that experienced leak repair personnel would be on standby to inject the valve if required to perform the actuator work.

During the actual corrective maintenance, the inspector observed excellent control and maintenance supervision. The environment in the condenser bay was such that a 20 minute stay time was imposed for the workers. The inspector observed excellent planning to accommodate this by having two technicians working on the valve at a time with substitution of one worker made every ten minutes to have continuity in the task where one technician, and the supervisor, were always aware of the job's progress. A remote camera was also focused on the valve to allow other workers and the engineers to observe the task. Because the time was invested in the mock-up training, when conditions were different than expected, technicians quickly identified problems. When the actuator spring was observed to be catching on the housing and again when two of four hold-down bolts were unexpectedly found sheared, the inspector observed supervision back out of the area, discuss the situation at the mockup with maintenance and engineering personnel, revise the MR, and build additional tools as needed.

Operators and maintenance personnel were successful in fully closing the valve prior to actuator disassembly, so the simple gag was used. No valve movement was observed during the evolution. A leak repair was not required prior to the corrective maintenance. The actuator diaphragms were successfully replaced and the glycol filled as planned. Other components of the actuator were also replaced, including the bottom diaphragm housing. Additional parts were taken from the spare FRV used for mock-up training.

c. Conclusions

The repair to the "B" FRV was well prepared and executed. Extensive mock-up training of all involved maintenance supervisors and technicians allowed a well written procedure and MR to be developed. In addition, the training served to familiarize the workers with the task so they could quickly detect potential disassembly problems during the "on-line" repair. Round-the-clock engineering support aided in the understanding of encountered problems and development of solutions. Management's decision to postpone the repair to the "B" FRV actuator until the week of November 8 was focused on safety. It allowed additional simulator and mock-up training for operators and maintenance personnel involved which resulted in a professional and well controlled corrective maintenance activity.

M2.2 "B" Reactor Building Closed Cooling Water Heat Exchanger Repairs

a. Inspection Scope (62707)

As described in NRC IR 96-06, Section I.O1.3, a through-wall leak was discovered on the salt service water side of the "B" RBCCW heat exchanger on September 17, 1996. The inspector observed portions of the repair to the heat exchanger and also performed periodic checks of the channels for the "A" and "B" RBCCW and turbine building closed cooling water (TBCCW) heat exchangers following the repairs to assess the corrective maintenance effectiveness and identify degradation of the heat exchangers that were not repaired during the outage. Review of the root cause evaluation for the leak is documented in Section III.E2.1 of this report.

b. Observations and Findings

After the "B" RBCCW heat exchanger was drained, the channel was removed to facilitate a 100 percent interior visual inspection and weld repair of two identified longitudinal cracks. Both the original and initially identified cracks were located on the inlet side of the channel, near the partition plate. Additional examination identified cracking in the bottom reinforcement plate to channel welds for both the lower and upper partition plates.

The inspector observed good control of the corrective maintenance to the heat exchanger. Extensive engineering, quality assurance, and maintenance supervisory oversight of the job was maintained throughout the repair. Maintenance personnel communicated well with quality control inspectors to verify the welds as they were completed.

The crack repair consisted of excavating the previous weld area and then performing the weld repair. The cracks were repaired by complete excavation and welding per the requirements of ASME Section XI and ASME Section VIII, the construction code for the heat exchanger. BECo maintenance personnel performed the grinding/excavation portion of the work and qualified vendors performed the weld repairs per the requirements of ASME Section XI. The inspector observed careful and thorough completion of the weld repair to the "B" RBCCW heat exchanger channel. Grinders sought supervisory guidance to ensure the flaws were excavated to the appropriate depth.

After the work was completed and throughout the remainder of the period, the inspector examined the "B" RBCCW and noted a leak-tight repair. In addition, the inspector periodically inspected the exposed channels for the "A" RBCCW and "A" and "B" TBCCW heat exchangers and detected no indications of degradation.

c. Conclusions

A careful and thorough Code repair was made to the "B" RBCCW heat exchanger channel head. The original through-wall leak and other cracks were excavated and weld repaired in a meticulous manner. Appropriate control of the corrective maintenance was evident, and the work was well supported by engineering and quality assurance personnel.

M4 Maintenance Staff Knowledge and Performance

M4.1 Electrical Maintenance Work During RBCCW Outage

a. Inspection Scope (62707)

Portions of two electrical maintenance activities were observed during the "B" RBCCW heat exchanger unplanned outage. One activity related to the replacement of the motor actuator on MO-1301-48, RCIC pump discharge injection valve no. 1. The second activity involved the swap out of the electrical breaker for the "D" SSW pump which became overloaded and damaged just prior to restart from the unplanned outage.

b. Observations and Findings

The inspector observed three electricians replace the motor actuator on MO-1301-48. Discussions were held with the electricians and the work package was reviewed which was quite lengthy because the actuator change-out was part of a modification package. The electricians experienced difficulty using a crimping tool (part no. 599751) to install electrical connectors on the end of electrical leads to the motor operator. The connectors were insulated with a plastic coating. The inspector questioned the electricians if the work package provided any specific guidance how to install the connectors. After review of the work package instructions, the inspector identified that the incorrect crimping device was used. Attachment 1 of procedure 3.M.3-51, Electrical Termination Procedure, specified that crimping tool 59974-1 be used for insulated terminations. Thus, the electricians were using the crimping tool for bare terminations rather than the specified tool for insulated terminations.

The inspector also questioned the integrity of the previously performed cable terminations. The electricians obtained the correct crimping tool, removed several connectors from earlier work, and installed the connectors properly. The inspector informed the electrical maintenance supervisor who was in the maintenance shop. The supervisor discussed the problem with the electricians and the maintenance department manager. Subsequently, the electricians completed installation of the new motor actuator which was successfully post work tested. Although the failure to follow procedural instructions during safety-related work was a violation identified by the NRC staff, the inspector acknowledged the long-term BECo corrective actions planned in the area of procedure quality and adherence. Further, the previous routine NRC staff report (i.e., 96-06) contained a Notice of Violation with several examples of procedural issues. This violation constitutes a violation of minor significance and is being treated as a non-cited violation in accordance with Section IV of the NRC Enforcement Policy.

Several days later, the inspector encountered the same group of electricians replacing the "D" SSW pump 480 volt electrical supply breaker. The work emerged when operators started the "D" SSW and the breaker tripped on thermal overload. This occurred shortly before plant startup so the work was handled as a Priority 1 activity A quality control inspector and maintenance supervisor observed the work. The electricians were very familiar with the breaker replacement. The electricians were careful to observe the minimum bend radius of breaker electrical cables. Lifted leads were independently verified and documented on a lifted lead log. After installation of the replacement breaker, a satisfactory post work test verified correct breaker operation and plant startup commenced.

c. Conclusions

Electricians were observed using an incorrect electrical crimping tool during replacement of the motor actuator on MO-1301-48. The electricians obtained the correct tool and reworked previously installed electrical connections. Using the incorrect tool resulted from not utilizing the procedural instructions. However, several days later just prior to plant restart, the same electricians competently replaced a 480 volt electrical supply breaker for the "D" SSW pump as a Priority 1 activity which emerged just prior to plant restart.

M6 Maintenance Organization and Administration

M6.1 Refueling Outage No. 11 Preparations

a. Inspection Scope (62707)

A review was performed to assess BECo's preparations for the next refueling outage (i.e., RFO11) which is preliminarily scheduled for 34 days from February 1, 1997 through March 6, 1997. Special emphasis was placed on the evaluation of shutdown risk, any significant changes from the previous refueling outage (RFO), and any major scope changes that may impact RFO11. The inspector interviewed the outage manager, plant manager, and ORC chairman and reviewed various documents including the preliminary outage work schedule and an outage performance enhancement task (OPET) force report issued in 1993.

b. Observations and Findings

The outage safety review team had not completed the RFO11 safety review report at the end of this inspection period. The outage safety review team plans to issue a TP that contains compensatory measures for various equipment/train unavailability windows. BECo recently purchased computer software to model risk and was in the process of refining the software to adequately depict shutdown risk at PNPS. As an end product, BECo plans to develop a curve of shutdown risk for the outage duration. The inspector obtained and reviewed several graphs of decay heat vs. time that illustrate the heat-up rate if shutdown cooling was lost and the time-to-boil. The shortest time-to-boil of 2.5 hours occurs the first day of RFO11 when the decay heat load is the highest and the reactor vessel is filled to the flange level. At this point early in RFO11, electrical bus A5 remains operable, supporting the "A" loop of shutdown cooling, while electrical bus A6 will undergo major load shed testing which makes the "B" loop of shutdown cooling unavailable during portions of the testing. If the "A" loop was lost, manual operator actions would be needed to restore the "B" shutdown cooling loop. The ORC chairman, who also functions as a member of the outage safety review team, informed the inspector that the load shed surveillance test will contain a specific restoration section as a contingency to stop the load shed testing and promptly restore the "B" loop of shutdown cooling if the "A" loop is lost. The time-to-boil increases as expected during the outage duration due to the lower decay heat rate and the extra volume of water after flood-up and opening of the spent fuel pool gate. The ORC chairman informed the inspector that operators would receive special briefings on RFO conditions and management of shutdown risk during the operator requalification training cycle. The inspector determined that BECo clearly understood when the shortest time-to-boil occurs, had actions underway to utilize computer software to develop a shutdown risk curve and intended to complete an outage safety review to issue a report including compensatory measures.

The inspector reviewed the outage scope that included a full core offload to facilitate replacement of the 102 core plate plugs. Previously, the NRC Nuclear Reactor Regulation (NRR) project manager reviewed the licensing aspects of a full core offload and determined that PNPS contained no implicit or explicit prohibitions that prevent full core offload as documented in Section 4.1 of NRC Inspection report No. 50-293/96-02, dated May 8, 1996. The "B" battery discharge test was moved up from RFO11 and performed during the unplanned outage to repair the RBCCW heat exchanger, which simplified the invessel

window of the critical path schedule sequence. Performance indicators, dated November 15, 1996, used by the outage manager showed approximately 1/2 of the preventative maintenance and corrective maintenance tasks were ready to work, and approximately 1/3 of modification packages were ready for work. The outage manager explained that many of the modification packages were on parts restraint until the beginning of 1997.

An emergent issue that may significantly impact RFO11 involves increased drywell dose rates. BECo observed higher than expected drywell dose rates during the September 1996 unplanned outage to repair the "B" RBCCW heat exchanger. Senior site management formed a task force to evaluate the potential causes of the increased drywell radiation levels. The team determined the probable cause was cobalt-60 deposition resulting from the combined effects of an increased hydrogen water injection rate and the continued perturbations of the hydrogen injection system. The team made several recommendations to senior site management to minimize the collective radiation dose during RFO11 and future RFOs. The team recommended that a zinc injection system be installed and operated prior to RFO11. Other options were under evaluation such as work deferral. BECo planned to perform a chemical decontamination of the reactor coolant system during RFO12.

Many tangible changes were implemented to improve overall RFO work control and execution. The work control process was totally revised in late 1995. A new work control department was created and staffed with experienced personnel during 1995 that reported directly to the plant manager. Benefits from these changes were evident during the previous two shutdown outages and an overall reduction in the corrective maintenance backlog. A work-it-now (WIN) team significantly contributed to a more timely correction of minor maintenance items. A new RFO manager has been appointed. A new outage control center is under construction in the administration building and is scheduled to be completed and in use for RFO11. The center will be staffed 24 hours a day during the outage. Outage team leaders/project managers have been assigned for the major outage projects.

Senior site management plans to use 8 General Electric Co. (GE) fuel handlers who will be under the direction of a BECo SRO on the refueling bridge during core offload and reload activities. As a team building initiative, BECo plans to send 12 BECo personnel to the General Electric Maintenance facility in San Jose, California during the week of December 2, 1996. The GE fuel handlers and the BECo refueling SROs will practice fuel movements. Contract fuel handlers will be used to reduce the burden on the resources of the operations department which will be the limiting factor early in the outage during the work release process. Additionally, other BECo workers will receive training on invessel work (i.e., change core plate plugs) to allow more effective oversight of contracted invessel work. Lastly, a major modification to the entrance/exit area (redline area) of the radiological controlled area (RCA) is under construction and scheduled to be complete and in use before RFO11. A new building was built on both sides of the existing breezeway to the RCA entrance. The modification was developed after RFO10 by the outage performance enhancement team. The number of exit portal monitors will double from 5 to 10 allowing easier personnel egress. Two small article monitors (SAMs) will be obtained. The control of contaminated tools, a previous NRC concern during RFO10, should also be more rigorous. These changes since RFO10 indicate a commitment to improve overall RFO performance.

c. Conclusions

Extensive RFO11 preparations were underway including several initiatives to improve overall outage coordination and execution. The planned use of contractor fuel handlers under the direction of BECo SROs demonstrated a substantial commitment to reduce the burden on the operations department during the outage. A computer-based risk model was being developed to produce a shutdown risk curve, for the first time, over the outage duration. Two emergent items involving increased drywell radiation levels and the ECCS suction strainer modification have the potential to impact the established outage scope.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Licensee Event Report (LER) 50-293/94-05: Automatic Scram Resulting From Load Rejection at 100 Percent Power

a. Inspection Scope

The inspector reviewed Licensee Event Report (LER) 94-05, Automatic Scram Resulting from Load Rejection, submitted to the NRC on September 28, 1994, and LER 94-05 Supplement 1, submitted on September 21, 1996 to verify accuracy, description of cause, previous similar occurrences, and effectiveness of corrective actions. The LERs were also reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022 and its supplements.

b. Observations and Findings

LER 94-05 reported an August 29, 1994 automatic scram which resulted from a load rejection at 100 percent power. The load rejection was automatically initiated by a main generator faulted condition. Subsequent to the scram, water level decreased below the low reactor vessel water level setpoint (+12 inches) and automatically initiated the reactor building isolation control system (RBIS). This actuation resulted in the automatic start of the standby gas treatment system and automatic closure of the reactor building/secondary containment system trains "A" and "B" supply and exhaust ventilation dampers. These actions went to completion with the exception of the closure of the in-series reactor building clean area supply dampers, AO-N-80 and AO-N-81, which indicated mid-position in the control room. These dampers were subsequently locally manually closed. BECo evaluated the event conditions and concluded that secondary containment was not significantly degraded by the partially open dampers and no 10CFR50.73 report was required.

A complete description and evaluation of this event was documented in NRC Inspection Report (IR) 94-18, Sections 2.3, 2.5, and 2.5. Unresolved item (UNR) 94-18-01 was opened pending inspector review of MDAT conclusions. The unresolved item was closed in IR 94-25, Section 2.2.1.

A multi-disciplined analysis team (MDAT) was formed to investigate the root causes of the event. LER 94-05 stated that a supplement report would be submitted after the MDAT team report was finalized and significant corrective actions were identified. The estimated

submittal date was November 30, 1994. The final MDAT report was issued in January 1995. The inspector noted a long time delay between the root cause determinations and the submittal of the LER supplement in September 1996.

LER 94-05 and its supplement accurately documented the event, corrective actions taken and planned, and the root causes for both the main generator faulted condition and the incomplete closure of the secondary containment dampers.

During the review of LER 94-05 and its supplement, the inspector noted that one of two in-series secondary containment dampers (AO-N-79) failed to fully close after an RBIS signal in November 1993, as documented in LER 93-26 and PR 93.9461. BECo appropriately identified this similar occurrence in LER 94-05. LER 94-05 further documented a March 1995 failure of damper AO-N-81 to fully close while the reactor was shutdown. The inspector questioned why the corrective actions for the 1993 event did not prevent the 1994 event and likewise why the corrective actions taken for the 1994 event did not preclude the 1995 event. Investigation for the 1993 damper, AO-N-79, revealed dirt and spray lubricant buildup prevented the damper from fully closing. Following the 1993 event, all other accessible dampers were inspected and cleaned. Procedure 8.7.3.1, Inspection of Secondary Containment Dampers, was used for the inspection and was revised to preclude the lubrication of components inside the damper assembly and a step was added to inspect blade ends and side seals for dirt or oil buildup. The inspector verified that the procedure currently contains these instructions.

The inspector noted that the root cause for the failure of AO-N-80 and 81 to fully close after the 1994 event was determined to be an accumulation of lubricant and dirt along the side seals; the same condition described for the 1993 event. Following this event, BECo determined that a more frequent inspection of the damper was needed and changed the frequency from annual to semi-annual. The additional corrective actions to rebuild the actuators had not yet been performed when the 1995 event occurred. Through discussion with engineering personnel and review of PR 95.9140, the inspector discovered that the root cause for the 1995 event was that the dampers' (80 and 81) actuators did not move readily in the actuator cylinders and were in need of cleaning/rebuild. It was also postulated that the root cause of the previous events was not the buildup of dirt and lubrication, but was primarily an actuator corrosion problem. The inspector concluded that the initial root cause evaluations performed for the 1993 and 1994 damper failures were not complete and it wasn't until the 1995 evaluation that the bonafide root cause was discovered. The inspector did note, however, that the preventive maintenance which was scheduled as a result of the 1994 event would have identified the actuator problem identified in 1995, but had not been completed when the 1995 event occurred.

The inspector verified that all secondary containment dampers were rebuilt during RFO10 in Spring 1995. In addition a preventive maintenance repetitive task was established in response to the 1994 problem report to ensure the actuators are rebuilt every 4 to 5 years. The inspector independently verified all secondary containment dampers are scheduled for rebuild in the 1999 refueling outage (RFO12).

c. Conclusion

LERs 94-05 and 94-05 Supplement 1, provided a complete description of the August 1994 reactor scram and developed root causes. The LERs properly addressed all reporting criteria. Root cause evaluations performed after a 1993 damper closure failure and the 1994 secondary containment damper failures during the subject scram were not complete. Although the corrective actions planned for the 1994 failures were broad enough to have found the root cause, it wasn't until a 1995 evaluation of an additional damper failure to fully close that the bonafide root cause was discovered. Since appropriate corrective actions for the damper failures had been identified after the 1994 event and were subsequently performed after the 1995 event, **Licensee Event Report 94-05 and its supplement are closed.**

M8.2 (Closed) Violation EA95-010: Primary Containment Boundary Degraded Due to Failure to Follow Calibration Procedure

On December 28, 1994, I&C technicians discovered a missing plug on the torus atmosphere portion of a drywell-to-torus atmosphere differential pressure transmitter. NRC inspection report 94-26, Section 3.2 documented the event. A Severity Level III Violation, Violation EA95-010, was issued on March 3, 1995. The Notice of Violation (NOV) contained two violations. The first involved the failure to maintain primary containment integrity for approximately 30 days while the reactor was critical. The second involved two examples of a failure to follow the calibration procedure which resulted in the breach of containment integrity.

On January 27, 1995, LER 94-07 was written to report the event. This LER was closed in NRC Inspection Report 96-01. As part of the closure for the LER, the inspector verified that corrective actions documented in the LER were completed. This period the inspector verified that additional corrective actions cited in BECo's response to the NOV, that were not delineated in the LER, were complete. These actions included revisions to various station procedures. The inspector verified that the additional corrective actions were complete. Therefore, **Violation EA95-010 is closed.**

III. ENGINEERING

E1 Conduct of Engineering

E1.1 (Open) IFI 96-08-01: Safety Evaluation Process Enhancements. Determination of Boraflex Degradation in Spent Fuel Pool Storage Racks

a. Inspection Scope (37551)

On June 26, 1996, the NRC issued Generic Letter (GL) 96-04, Boraflex Degradation in Spent Fuel Pool Storage Racks. The GL requested, in part, that licensees, "...provide an assessment of the physical condition of Boraflex in the fuel storage racks, including any deterioration,...and state whether a subcritical margin of 5 percent can be maintained for the racks in unborated water." BECo conducted testing on one of nine potentially affected spent fuel pool storage racks in September 1996. The inspector reviewed the temporary

procedure used for the testing, attended the original pre-evolutionary brief, reviewed the preliminary test results and operability determination, and discussed the results with the cognizant engineer to determine whether an operability concern existed.

b. Observations and Findings

Nine of the Pilgrim spent fuel pool storage racks contain the Boraflex material. Sheets of Boraflex material are "sandwiched" between welded steel assemblies to form the spent fuel pool storage racks. Boraflex is a silicon-based polymer which includes an imbedded Boron-10 poison which absorbs neutrons, thereby assuring an adequate shutdown margin is maintained in the spent fuel pool when spent and new fuel assemblies are stored in the racks. Experimental data from test programs has shown that Boraflex panels similar to those installed at Pilgrim have demonstrated shrinkage manifested by stress-induced gaps in the Boraflex sheets.

BECo performed "blackness" testing on one of their Boraflex spent fuel storage racks to determine the condition of the Boraflex. "Blackness" testing is performed by placing a neutron source on one side of the material to be tested and monitoring the neutron flux reflected back to a detector. A "black" material absorbs the neutrons, therefore very little flux is reflected and detected. However, if the material, Boraflex in this instance, has degraded or is no longer present, much of the source neutron flux is detected. TP 96-32, Blackness Testing in the Spent Fuel Pool, was developed to control the testing. BECo worked closely with Holtec International, the vendor contracted to perform the work, to develop the procedure.

The thorough initial PEB was given by the test director who provided operators background on the reason for testing, discussed the affected technical specification Section 5.5.B and GL 96-04, and described the method for performing the test. Foreign material exclusion and radiological work practices were also reviewed. The test director and nuclear operating supervisor (NOS) communicated the abort criteria for the test.

The preliminary testing results indicated shrinkage and gapping of the Boraflex material, as predicted by industry data. PR96.9561 was initiated to document and evaluate these results. The test showed approximately 4 inches of end shrinkage on the 136 inch panels with maximum gapping estimated at less than 2 inches. The inspector reviewed the operability determination performed based on the original test results. The test results indicated shrinkage within the 4 percent found in similar industry tests. BECo determined that the observed Boraflex shrinkage and gapping did not reduce the 5 percent margin required by technical specifications. Therefore, the racks and spent fuel pool were found to be operable.

The inspector attended the ORC meeting at which the operability evaluation was reviewed. The preliminary evaluation checklist (PEC) was completed to determine whether a 10CFR50.59 safety evaluation was required for the Boraflex condition. A PEC concluded that no safety evaluation was required, but indicated in the comment section that once the final test report results and criticality analysis were obtained from Holtec a safety evaluation may be needed. Prior to attending the ORC meeting, the inspector questioned why the PEC

determined no safety evaluation was needed when the comment indicated one may be needed. The inspector noted good ORC review of the evaluation which also determined a 50.59 safety evaluation was required and should be so noted on the PEC.

The inspector further reviewed the guidance given to engineers for performing 50.59 evaluations. After a 50.59-related evaluation for another issue earlier this year, the inspector understood that "preliminary" 50.59s would be performed if it was determined that one was needed but further calculations or information was required to do a complete/formal evaluation. Based on this understanding the inspector discussed this issue with the engineering services group manager who determined that better guidance was needed to direct engineers to perform the reviews consistently. The inspector discovered that the guidance to perform "preliminary" safety evaluations for operability issues reviewed under NRC Generic Letter 91-18 was in Nuclear Engineering Department Work Instruction (NEDWI) 395, Revision 4. Since the information was in a work instruction and not delineated by the program procedure (i.e., NOP83E5), the engineer was not required to perform the review in accordance with it. Therefore, no procedure was violated. In fact, when the inspector discussed the issue with the engineer he indicated that since no guidance was given in the governing procedure, Nuclear Organization Procedure (NOP) 83E5, Safety Reviews, on how to write a preliminary evaluation, he deferred to the NOP instead of the NEDWI. The Engineering Services Group Manager agreed to: a) review the phraseology in the PEC sheet, b) proceduralize the preliminary 50.59 safety evaluation process, and c) revise the NOP, as needed. This item will be tracked as **Unresolved Item (UNR) 96-08-01**.

After the ORC meeting, a preliminary 50.59 safety evaluation, SE 3017, was performed. The inspector determined the evaluation was complete and answered all appropriate questions to determine no unreviewed safety questions existed. BECo subsequently received the Holtec report which was bounded by the field observations. Holtec was tasked to perform a criticality analysis using the new data. Following review of this analysis, BECo plans to update the safety evaluation for the degraded Boraflex condition, if required.

c. <u>Conclusions</u>

Blackness testing of a Boraflex spent fuel pool storage rack was conducted using a temporary procedure developed by BECo with vendor input. The initial pre-evolutionary briefing was thorough and discussed background information, test method, effect on control room operators, and abort criteria. Thorough ORC review of the operability evaluation for the preliminary test results determined that a 50.59 safety evaluation was required to disposition the observed Boraflex degradation. An appropriate review was subsequently performed and determined no unreviewed safety question existed. A weakness was noted in the safety evaluation process, which led to the improper engineering determination that a safety evaluation was not needed. This area will remain as **Unresolved Item (UNR) 96-08-01** pending further BECo and NRC staff review.

E2 Engineering Support of Facilities and Equipment

E2.1 (Closed) Inspector Follow Item (IFI) 96-06-01: Root Cause Analysis for "B" RBCCW Heat Exchanger Through-Wall Leak

a. Inspection Scope (37551, 92903)

As discussed in Section II.M2.2, a through-wall leak was discovered on the SSW side of the "B" RBCCW heat exchanger on September 17, 1996. Following this discovery, PR96.9473 was issued to document and determine the root cause of the problem. The inspector reviewed the root cause evaluation and discussed the results with BECo engineering personnel. In addition, the inspector reviewed the operability evaluation for the RBCCW and TBCCW heat exchangers to determine their adequacy to justify operation of all heat exchangers until the planned February refueling outage.

b. Observations and Findings

In response to PR96.9473, engineering personnel investigated the root cause of the through-wall leak on the "B" RBCCW heat exchanger channel. The root cause was fatigue caused by cyclic loading of the attached lower partition plate. This plate is used to direct the inlet SSW flow through the first of four passes in the RBCCW heat exchangers. The cyclic loading was caused by flow impingement of the SSW and fluctuating differential pressure across the lower partition plate. This loading was transmitted to the heat exchanger shell in the form of bending at the partition plate junction. The partition plate is welded to the channel shell and the described bending loads were transmitted into the shell at this point. Backwashing was also found to have contributed to the fatigue failure, since during a backwash the applied differential pressure is reversed and a stress reversal results in the channel shell.

A structural analysis of the Code repair on the inlet channel of the "B" RBCCW heat exchanger was performed for BECo by Duke Engineering & Services to verify the acceptability of the repair for use of the heat exchanger until the planned February 1997 refueling outage. It also served to verify the root cause and operability evaluations. The inspector noted that the RBCCW heat exchanger was built and repaired to the requirements of ASME Section VIII, Division 1; however, the calculation was performed by the vendor to ASME Section VIII, Division 2. The analysis per Division 2 provided for a more rigorous analysis using finite element evaluation for the fatigue analysis instead of the "design by formula" provisions in Division 1. The analysis concluded that the allowable number of cycles on the channel plate and shell before failure was 340. BECo estimated that 2 cycles of the heat exchanger are expected per week until the outage, allowing a large margin to failure. The September 1996 failure occurred after more than 340 cycles. The inspector noted proper BECo oversight of vendor services as indicated by BECo identification of an incorrect partition plate thickness value used in the original vendor analysis. The calculation was revised to include the proper value and no change in the evaluation conclusions resulted.

The results of the fatigue evaluation were used to confirm the original operability evaluation for the "A" RBCCW and "A" and "B" TBCCW heat exchangers. The operability evaluation was based on reduced duty of the "A" RBCCW compared to the "B" RBCCW heat

exchanger and reduced size and differential pressure across the TBCCW heat exchangers compared to the RBCCW heat exchangers. The inspector determined the operability evaluation for the heat exchangers was reasonable and appropriately included all RBCCW and TBCCW heat exchangers in the scope.

BECo had previously identified that the original design of the partition plates was inadequate. Plant Design Change 81-55 modified the RBCCW heat exchanger partition plates. Because of the inadequate partition plate design, the RBCCW and TBCCW have a long history of modifications and repairs. In 1991 the "B" RBCCW partition plate buckled at the plate centerline and along the shell-to-plate junction. Many cracks were found and additional stiffening of the partition plates in both the "A" and "B" RBCCW heat exchanger was performed. This modification added stiffener plates to the partition plates, which increased the magnitude of the bending stress in the channel shell. Engineering personnel also informed the inspector that stress intensification of the welds occurred because the welds were not polished and some minor cracks were not repaired during the 1991 modification.

The original heat exchangers were designed using the fifth edition of the standards of the Tubular Exchanger Manufacturers Association (TEMA) which specified a partition plate thickness of 1/2 inch. The 1988 revisions to the TEMA standard upgraded the determination of this thickness as a result of industry experience and incorporated a formula to determine partition plate thickness. This formula now specifies a thickness of 1.25 inches. A finite element analysis was performed for the 1991 evaluation, however the stresses on the partition plate were analyzed not the stresses on the shell. A fatigue analysis was not performed for the modification since it was beyond the normal scope of such a modification and was not required. Had it been performed, the fatigue concern may have been identified.

The inspector reviewed GL 89-13 and determined the subject of the GL was salt service water heat exchanger heat transfer capability and testability and not structural integrity. The responses to the GL and NRC review of related areas would therefore not have included a review of this structural integrity problem.

BECo had been in the process of designing new channels for the "B" RBCCW and TBCCW heat exchangers which the through-wall leak developed. As a result of the leak and subsequent root cause and fatigue analyses, BECo has ordered new channels for all of the RBCCW and TBCCW heat exchangers. These channels are currently scheduled to be replaced in the February refueling outage. Partition plates in the RBCCW heat exchangers will be 1.5 inches thick, building extra conservatism into the TEMA specifications.

c. Conclusions

A finite element analysis was performed by a vendor to determine the acceptability of the "B" RBCCW heat exchanger following the Code repair. The results of this analysis were appropriately used to validate assumptions made in the root cause analysis and operability evaluation. BECo maintained proper oversight of vendor services as evidenced by BECo identification of an incorrect partition plate thickness value used in the original fatigue analysis for the failed "B" RBCCW heat exchanger. After a history of repairs and modifications of the original design for the RBCCW and TBCCW heat exchanger partition

plates, BECo had initiated a design change to the plates and channels. However, these planned modifications were not timely enough to preclude the September 1996 shutdown after a through-wall leak was discovered in the "B" RBCCW heat exchanger channel. BECo's plan to upgrade and replace the channels in all four heat exchangers during the February 1997 outage is appropriate.

E2.2 Engineering Related Outage Issues

a. Inspection Scope (37551, 92903, 93702)

Engineering support of unplanned outage activities was monitored during plant manager morning meetings, review of events and during the execution of outage-related work.

b. Observations and Findings

b.1 Loss of Shutdown Cooling Event

A loss of shutdown cooling (SDC) occurred September 25, 1996 for 40 minutes with a resultant increase in moderator temperature of 12 degrees Fahrenheit from 99 to 114 degrees. Operators responded well by promptly restoring SDC. The event occurred due to a false high reactor vessel pressure signal when backfilling a reactor pressure transmitter. Operators made the requisite NRC notification pursuant to 10 CFR 50.73(a)(2)(iv). BECo also submitted LER 96-09, dated October 25, 1996, to the NRC. Backfilling the reference legs associated with nonsafety-related condensing chambers 13A and 13B is necessary prior to each startup to mitigate the effects of noncondensible gases causing inaccurate level indication during depressurization. A continuous reference leg fill system was installed prior to this event for safety-related condensing chambers 12A and 12B.

The inspector discussed this event with the engineering department manager and reviewed LER 96-09. The cause of the event was a deficiency in Attachment 2 of procedure 3.M.2.12.4, Backfilling Reference Lines. The procedure did not recognize that SDC needed to be secured when backfilling the sensor lines of reactor pressure detector PT-263-50A. Procedure 3.M.2.12.4 Attachment 2 should have been modified after the implementation of plant modification PDC 94-12 which, in part, changed the SDC isolation logic to 1-out-1 taken once. The engineering plant impact review for PDC 94-12 did not identify the need to modify procedure 3.M.2.12.4 and, therefore, was inadequate. Similarly, procedure 3.M.2.12.3 for backfilling the sensing lines for reactor pressure transmitter PT-263-50B was also deficient for the same reason. The procedures were subsequently revised. The safety consequence of the loss of SDC remained low since moderator temperature increased just slightly following the loss of SDC due to prompt and effective operator response.

A BECo 1996 common cause analysis of the previous 12 months of adverse human performance identified the impact of modifications as the most common cause. The second most common cause involved procedure adherence and quality. Corrective actions were underway in this area prior to this event to improve performance as documented in NRC Staff Inspection Report No. 50-293/96-06. The inadequate procedure constitutes a **non-cited violation** consistent with section VII.B.1 of the NRC Enforcement policy.

b.2 I&C Rework of SRM Settings Due to Procedure Adherence Problem

A second engineering performance related matter resulted in I&C rework when the source range monitor (SRM) discriminator settings for the "A" and "D" SRMs had to be reset. During the close-out review of procedure 3.M.2-5.1.4, SRM Discriminator Setting, the NWE identified that a system engineer and I&C did not follow procedural Step 5 of Attachment 1 which leaves the setting that produced the highest neutron count. The voltage was left at 350 vice 600. The I&C department engineering manager initiated PR96.9500 to document and evaluate this problem. The settings for the "A" and "D" SRMs were redone in accordance with the written procedural steps prior to plant restart. The "B" and "C" SRMs had been previously completed appropriately by other personnel. The inspector interviewed the system engineer, reviewed the signed off version of procedure 3.M.2-5.1.4 in use at the time and held a discussion with the engineering manager. The system engineer instructed I&C to leave the high voltage setting at 350 VDC vice 600 VDC by placing a note in the acceptance criteria section of the procedure. The note stated, in part, "per system engineer instructions". The system engineer stated that he was attempting to leave the settings at the lower voltage for increased SRM detector reliability. In addition to the NWE who identified this issue, the inspector also considered this a procedural adherence problem. The inspector recalls a similar use of a notation by an engineering test director during the ECCS pump motor inspection work documented in Section II.M4.1 of NRC Inspection Report 96-05. The use of a note in the acceptance criteria section in lieu of obtaining a procedure change is an informal and poor practice. This failure to follow procedure constitutes a **noncited violation** consistent with Section VII.B.1 of the NRC Enforcement Policy. Also, corrective actions were underway in this areas prior to its event to improve performance as documented in NRC Staff Inspection Report No. 50-296 96-06.

b.3 Improved SRM and IRM Reliability

As previously mentioned on Section I.O4.1 of this report, the inspector witnessed improved performance of SRMs and IRMs which adversely impacted the previous startup. After that startup, the plant manger placed the SRM/IRM undervessel problems on the plant manager's top 10 list of equipment problems. In light of the importance of monitoring reactivity during all phases of reactor operation, the engineering department designated an issue manager to solve problems associated with the neutron monitoring system. A root cause analysis team was formed to determine corrective actions needed prior to restart from the September 18, 1996 shutdown. Diagnostic testing was performed on each SRM and IRM channel including current versus voltage testing, insulation resistance testing and signal cable ground resistance testing. Fine tuning was done. The "A" and "C" IRM detectors were replaced. A design change (FRN 96-01-130) was implemented on the "A" and "C" IRMs and "D" SRM cable connectors. The change installed an "O" ring between the detector retainer and cable guard to improve leak resistance of the SRM/IRM cable guard. A different qualified connector (FRN 96-04-77) will be installed during RFO11. BECo sent workers to the Oyster Creek nuclear facility to gain experience installing the new type of connector. A last recommendation made by the issue manager was to procure high precision test equipment for future diagnostic testing. A notable improvement was observed by the inspector in the performance of IRM/SRMs during plant restart.

c. Conclusions

A brief loss of shutdown cooling occurred on September 25, 1996 due to an inadequate procedure used to backfill reference legs for nonsafety-related condensing chambers 13A and 13B. An incomplete modification plant impact review resulted in the procedural deficiency. In an unrelated matter, I&C had to rework the SRM discriminator settings due to a procedural adherence issue involving a system engineer. Both issues were treated as **noncited violations** since both were self identified and promptly corrected.

Increased reliability of the SRM/IRMs was observed during plant startup which was an improvement over the previous startup. Engineering personnel conducted methodical diagnostic testing and completed related corrective maintenance including replacement of 2 IRM detectors and implementing an innovative design change for detector connectors.

E7 Quality Assurance in Engineering Activities

E7.1 Final Safety Analysis Report Self-Assessment

a. Inspection Scope (37551)

On October 9, 1996, the NRC sent a letter to all owners of nuclear power plants in the United States which requested information pursuant to 10CFR50.54(f) regarding the adequacy and availability of design basis information. In light of this letter, the inspector reviewed BECo's actions taken to date in this area with a focus on the assessment of the Final Safety Analysis Report (FSAR).

b. Observations and Findings

Prior to the issuance of the 50.54(f) letter, BECo had decided to perform a licensing basis review for PNPS. This review is currently in progress and includes a review of selected sections of the FSAR, reconstitution of the TS licensing basis as part of the conversion to standard TS, and a review of the past five years of licensing correspondence (i.e., violation and generic letter responses) and safety evaluation reports to identify commitments.

BECo's FSAR self-assessment did not include a complete verification of all sections in the FSAR. The review was focused on systems whose performance was determined to be most important for avoiding the potential of core damage. The inspector noted that these risk-significant systems included emergency core cooling systems, main steam, salt service water, RBCCW, emergency diesel generators and station blackout diesel.

The inspector discussed this review with the engineering manager assigned to control the assessment. The inspector discovered that system engineers were generally chosen to review their systems. The reviewers color-coded their sections to designate whether the reviewer 1) definitely knew the information to be correct, 2) believes to be correct, but would need to verify through more extensive document review, 3) knew or suspected the information to be incorrect, and 4) determined that it does not fit above categories. Most of the initial reviews have been completed and the results were in the process of being evaluated. BECo plans to make identified editorial changes with the next FSAR update scheduled for July 1997.

The inspector reviewed some of the annotated FSAR sections. The initial reviews appeared to be complete and identified all of the potential designations. Approximately 15-20 problem reports have been issued as a result of this review, but none involved operability concerns. The final review is scheduled to be complete for the February response to the NRC 50.54(f) letter.

c. Conclusions

A BECo initiative to review the UFSAR to determine whether PNPS was operating within the scope of the PNPS UFSAR was focused on safety-related and risk significant systems. The initial BECo results identified no significant problems involving operability.

IV. PLANT SUPPORT

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 (Open) VIO 96-08-02: Implementation of the Radioactive Effluent Control Program (RECP)

a. Inspection Scope (84750)

The inspector evaluated implementation of the RECP through a review of radioactive liquid effluent release permits and radioactive gaseous effluent release reports, associated procedures, sampling performance, the licensee's method for quantifying radioactive liquid and gaseous releases, the recent revision of the Offsite Dose Calculation Manual (ODCM), and projected dose calculations. The above areas were inspected against Section 3/4.8 in the TS, the ODCM, and UFSAR commitments.

b. Observations and Findings

Selected radioactive liquid release permits from the neutralizing sump and miscellaneous tanks, and weekly and monthly reports from the reactor building vent (RBV) and main stack were complete. The liquid release permits contained pertinent information such as a description of the tank or sump, the volume of liquid in the tank or sump, and activity concentration. Similarly, the gaseous effluent reports included results of weekly air particulate and charcoal sample analyses, and monthly and quarterly composite analyses. The licensee's method for quantifying radioactive liquid and gaseous releases were performed according to the ODCM.

The permits are the records of all routine releases from the plant and the sample results are used to calculate the projected doses to the public. The inspector reviewed the dose calculations from January to October 1996. The doses to the public, as a result of liquid and gaseous effluent, were calculated by a Senior Environmental Radiochemist weekly, more frequently than required by TS. The permits, dose projections, and assessments were verified by a Chemistry Manager. The dose projections were performed according to the methods described in the ODCM and are below regulatory limits.

The inspector observed a chemistry technician exchange the charcoal cartridge and particulate filter, and collect a noble gas sample from the RBV. The technician followed Procedure No. 7.3.25, "Particulate and Iodine Monitoring at the Main Stack and the Reactor Building Vent," and Procedure No. 7.3.37, "Determination of Conversion Factors for Gaseous Plant Vent Monitors," and demonstrated satisfactory sampling techniques and practices.

Review of the sample and analytical program revealed the sample and analytical frequency for the neutralizing sump, as established by the licensee, was inconsistent with TS. The inspector verified on October 1, 1996, that the sample and analytical frequency of the neutralizing sump had not been conducted in full compliance with the Technical Specification 4.8.A.1, Table 4.8-1 up until third quarter 1994. Technical Specification 4.8.A.1 states, in part, that monthly composites shall be analyzed for tritium (H-3) and gross alpha radioactivity and quarterly composites shall be analyzed for strontium-89 (Sr-89), strontium-90 (Sr-90), and iron-55 (Fe-55). The licensee analyzed for gross gamma, iodine-131 (I-131), and entrained and dissolved noble gases on each batch prior to discharge, as required, but did not sample and analyze the monthly and quarterly composites from this sump if no gamma activity was detected. This practice was described in Procedure No. 7.9.5, "Waste Neutralizing Sump Discharge Procedure," which allowed the normally non-contaminated sump to be discharged as a non-radiological release based on the non-detection of any gamma-emitting activity. When no gamma activity was detected, the procedure contained no provisions for the collection and analyses of monthly and quarterly composites for Sr-89, Sr-90, Fe-55, H-3, and alpha activity.

A batch sample result in July 1994 indicated gross gamma activity and H-3 in the neutralizing sump. Chemistry investigated the source of the H-3 and discovered that the neutralizing sump, usually used for non-contaminated liquids, had been receiving water from the Turbine Building Closed Cooling Water (TBCCW) system since June 1993. The licensee determined the cause was a degraded seal between TBCCW and feedwater in the outboard seal of the "A" Reactor Feed Pump (P-103A). The licensee repaired the leak in November 1994. Since the neutralizing sump was considered "contaminated", after this finding, the licensee followed a different procedure (Procedure No. 7.9.2, "Liquid Radioactive Waste Discharge") and analyzed the sump samples as required by TS. Although implementation of the technical specification after July 1994 is evidenced through records of sample results, this is not considered corrective action because the licensee did not recognize the noncompliance and as a result, the Procedure No. 7.9.5 would again permit discharges without compositing and analyzing if gamma activities again dropped.

The results of the July 1994 batch indicated a concentration of 6.23E-4 microcuries per milliliter (μCi/ml) of H-3 in the neutralizing sump. (No other radionuclides were detected.) Lacking any other reference analysis confirming previously released contents were not similarly contaminated, this concentration was assumed to have been released from each batch and the discharges were re-evaluated by the licensee back to June 1993 when H-3 was assumed to have entered the system. Based on this information, the licensee corrected the quarterly dose reports and determined the total amount of H-3 released increased slightly from 2.61 Ci to 2.66 Ci, the dilution increased from 1.63E9 liters to 1.87E9 liters based on the actual amount of water discharged, and the total body dose to the maximally exposed member of the public from all liquid pathways decreased from 6.0E-2 mrem/qtr to 5.2E-2 mrem/qtr for the second quarter in 1993. Corrections were

performed for the subsequent quarters and the results were similar. The dose effect was inconsequential, given the amount of dilution volume and negligible change in reported H-3 activity. The licensee documented the correction in the Semi Annual Effluent Release Report for 1994. Consequently, the inspector confirmed that this matter did not result in any safety consequence to public health and safety or the environment. The failure to sample and analyze monthly and quarterly composites of the neutralizing sump to analyze the non-gamma activity, in accordance with the requirements of the applicable technical specification, constitutes a violation of TS 4.8.A.1, Table 4.8-1 **(VIO 50-293/96-08-02)**.

c. Conclusion

Overall implementation of the radioactive liquid and gaseous waste sample and analytical programs was very good, however the observed inconsistency and associated violation indicated a need for thorough review of procedures, the technical specifications, and management oversight. The violation appeared to be isolated to the sample and analytical requirements of the technical specification regarding the neutralizing sump because the associated discharge procedure inadequately conveyed the intent of the technical specification.

The licensee's assessment and evaluation were appropriately documented using a conservative approach to assess the total quantity of tritium that may have been released during the periods in question and the resultant contribution to total dose to the environment. The licensee's assumptions were valid and reasonable, the additional tritium contribution to dose to the public was negligible.

R1.2 Radioactive Liquid and Gaseous Effluent and Process Instrumentation

a. Inspection Scope (84750)

Setpoints and operability for the liquid and gaseous effluent and process monitoring instrumentation were inspected against TS Sections 3/4.8.B and 3.4.8.E, the ODCM, and the UFSAR.

b. Observations and Findings

Operability was demonstrated by performing the channel calibrations and functional tests for the following Plant Radiation Monitors (PRM):

- Liquid Radwaste Effluent Line
- Main Stack Effluent Monitoring System
- Reactor Building Ventilation Effluent Monitoring System
- Steam Jet Air Ejector Radioactivity Monitor

The electronic and radiological calibrations and the functional tests were performed at the frequencies specified by TS. The results of these calibrations were within the established acceptance criteria prescribed in the associated procedures. The calibrations were performed using standards traceable to the National Institute of Standards and Technology (NIST), as recommended by Regulatory Guide 1.21. The functional tests verified that the

instruments were functioning properly. A Chemistry Manager reviews the results of the calibrations and compares the results to the previous year to verify reproducibility, reliability, and stability of the systems.

The setpoints were determined using the methods in accordance with the ODCM. The inspector observed the licensee calculate the setpoint using Procedure No. 7.3.37, "Determination of Conversion Factors for Gaseous Plant Vent Monitors."
The inspector observed the readouts of effluent PRMs in the main control room and toured the turbine building and reactor building vent PRMs. The PRMs were operable with their alarm/trip setpoints set to ensure that the limits specified by TS would not be exceeded.

c. Conclusions

The inspector concluded that the licensee has an excellent program to ensure operability of the radioactive effluent and process instrumentation. No discrepancies were noted in either the TS, the UFSAR, or ODCM.

R1.3 Testing of Air Cleaning Systems

a. Inspection Scope (84750)

The licensee's program for testing the following air cleaning systems was inspected against specific criteria in TS 3.7.B, and compared to the standards of ASME N510-1989, "Testing of Nuclear Air Cleaning Systems." Commitments in the UFSAR were also reviewed.

- Standby Gas Treatment System (SBGT)
- Control Room High Efficiency Air Filtration System (CRHFS)

b. Observations and Findings

The following tests were included:

- visual inspections
- HEPA filter bank in-place test
- adsorber bank in-place test
- airflow capacity test
- pressure drop test
- laboratory testing of adsorbent

The inspector toured the areas of the SBGT and the CRHF systems. During the tour, train B of the SBGT was operating. The licensee proceeded to conduct a check of the train including a verification that the pressure drop across all the filter banks was less than 8 inches of water. Using the Procedure No. 8.7.2.1, "Measurement of SBGT Filters and Fan Capacity", the licensee verified the pressure drop was within the criteria.

The procedures provided the required guidance to perform the above tests and meet the TS criteria. All reviewed test results met the criteria specified by TS. The tests were performed at frequencies specified by TS.

c. Conclusion

The inspector concluded that the licensee had implemented the TS requirements for testing the air cleaning systems effectively. No discrepancies in the UFSAR were noted.

R1.4 Implementation of the Radiological Environmental Monitoring Program

a. Inspection Scope (84750)

The inspector observed and assessed the licensee's capability to implement the radiological environmental monitoring program (REMP). The program was inspected against Sections 7.0/8.0 of the Technical Specifications (TS), Section 7.0 of the ODCM and Sections 2.6 and 7.14 of the Updated Final Safety Analysis Report (UFSAR).

b. Observations and Findings

The REMP was governed by administrative and implementing procedures, some of which were reviewed for technical content and application.

Procedure 7.12.1,	Administration of the Radiological Environmental Monitoring Program
Procedure 7.12.5,	Review and Evaluation of REMP Results
Procedure 7.12.10,	Assuring Proper Sampling Schedule is Maintained
Procedure 7.12.25,	Air Particulate and Air Iodine Filter Preparation and Collection
Procedure 7.12.30,	Surface Water Sampling
Procedure 7.12.35,	Milk Sampling
Procedure 7.12.40,	Exchanging TLDs
Procedure 7.12.60,	Garden Census
Procedure 7.12.65,	Milk Animal Census
Procedure 7.12.80,	Maintenance and Calibration of the Nuclear Air Sampler and Standard Sprague Dry Gas Meter

The above procedures, written to provide guidance for implementing the REMP, were clear, concise, and of very good technical content. Adherence to the procedures was evidenced through review of detailed documentation of discrepancy reports and logs; records of sample submission forms; reports of analytical results of environmental samples; records of air sampler calibration results; and visiting selected air, water, and milk sampling stations and locations where thermoluminescent dosimeters had been posted. The inspector observed contractor personnel, General Test Division (GTD), collect a "grab" sample of water from an upstream location and water from the compositor located at the discharge canal, collect milk and silage from the indicator farm, exchange air particulate filters and air iodine cartridges from the air samplers, and exchange certain thermoluminescent dosimeters.

Procedures 7.12.60 and 7.12.65 were used to conduct the Land Use Census required by TS. The census, performed in 1995, detailed garden and milk locations within 5 miles around the site. The results confirmed no significant changes from the previous census.

The results were published in the annual REMP report. The census for 1996 had been recently performed, therefore, the results were preliminary. The finalized results will be published in the REMP report for 1996.

Included within this inspection was a review of the effect, if any, of Hydrogen Water Chemistry (HWC) to members of public and environment using environmental TLDs. Quarterly environmental and onsite TLD results from 1990 - 1996 were compared as a mechanism for determining the impact of the HWC. It was noted that a certain onsite TLD showed an average delta dose increase of 13 mR/qtr based on an average dose before and after HWC. Other site TLDs were compared and similar results were noted. The environmental TLDs showed no increase, evidenced by the quarterly results published in the annual REMP report and confirmed in NRC collocated TLDs close to the site published in NUREG-0837, "NRC TLD Direct Radiation Monitoring Network."

No significant changes were made to the ODCM during 1995 and 1996 regarding the REMP. No deviations from the UFSAR regarding REMP commitments were noted.

c. Conclusion

Based on the above review, direct observations, discussions with personnel, and examination of procedures, the inspector determined that: (1) trending the impact of HWC on the environment and the public was an excellent initiative; and (2) the REMP continued to be excellent and implemented in accordance with the TS, ODCM, and UFSAR commitments.

R1.5 Meteorological Monitoring Program (MMP)

a. Inspection Scope (84750)

The MMP was evaluated to determine whether the instruments and equipment were operable, calibrated, and maintained according to the Emergency Preparedness Administrative Procedure, the Emergency Plan, and Section 2.3 of the UFSAR.

b. Observations and Findings

The Facilities and Equipment Team of the Emergency Preparedness Department continued to have responsibility to ensure that surveillances, calibrations, and maintenance of the meteorological monitoring equipment was performed. Contractors from GTD are responsible for performing weekly surveillances, which include maintenance as needed, and quarterly calibrations. Execution of surveillances, calibrations, biweekly exchanges of the strip chart recorder paper, and any occurrences pertaining to the primary and secondary towers were documented in a log book. The results of surveillances and calibrations were sent to the Facilities and Equipment Specialist for review of completeness and filing. The results of the surveillances and calibrations were within the defined acceptance criteria, documented in Procedure No. EP-AD-421, "Surveillance, Maintenance, and Calibration of MeDAP Equipment."

The primary meteorological tower is equipped with wind speed, wind direction, and temperature sensors at the 33-foot and 220-foot elevations, and the 160-foot backup tower is equipped with wind speed, direction, and temperature sensors at the 33-foot and 160-foot levels. The inspector observed the sensors and their readouts and noted that the meteorological data were available in the equipment house via digital display using a portable computer and in the control room via digital display from the system computer, and via analog strip chart recorders as noted in the UFSAR, Section 2.3.

The inspector witnessed a portion of the weekly calibration check of the meteorological instrumentation at the primary tower, including an examination of the strip chart recorders to verify the expected response to the calibration. The results were within the acceptance criteria. The chart recorders in the control room and the instrumentation at the primary tower were well maintained at the time of the inspection.

During a quarterly calibration in May 1995, the cable used to raise and lower the tower instrumentation snapped, causing the instrumentation to slide down the tower resulted in damaging the instrumentation. A Problem Report was generated, the root cause analysis was performed and immediate and long-term corrective actions were recommended and implemented to prevent recurrence. One recommendation was to revise the procedure to affect certain inspections and maintenance performed quarterly, yearly, and/or every five years. While the primary tower was inoperable, the backup tower became the primary source for meteorological data.

The inspector reviewed Procedure No. EP-AD-421, "Surveillance, Maintenance, and Calibration of MeDAP Equipment," Revision 2, dated December 15, 1995, and verified incorporation of preventive maintenance.

c. Conclusion

Based on the above review, direct observations, discussions with personnel, and examination of procedures and records for calibration of equipment, the inspector determined that: (1) calibrations and maintenance of the equipment were performed according to the procedure, (2) system reliability was high, and (3) the licensee continued to implement the program in accordance with UFSAR commitments and Regulatory Guide 1.23 recommendations.

R6 RP&C Organization and Administration

R6.1 Organization Changes and Responsibilities

a. Inspection Scope (84570)

The inspector reviewed any organization changes and the responsibilities with the Chemistry Department personnel.

b. Observations and Findings

There were no significant organization changes relative to oversight of the Radioactive Effluent Control Programs, since the previous inspection conducted in October 1995.

c. Conclusion

Based on discussion with the responsible personnel and the results of this inspection, the inspector determined that oversight of the effluent programs essentially remained unchanged.

R6.2 Semiannual Radioactive Effluent and Waste Disposal Reports

a. Inspection Scope (84570)

The Semiannual Radioactive Effluent and Waste Disposal Reports and the Annual Dose Assessment to the General Public from Radioactive Effluents reports were reviewed to verify the implementation of Section 6.9.C.1 of TS.

b. Observations and Findings

The semiannual reports for 1993, 1994, 1995 and first half 1996 provided a comprehensive summary of the total released radioactivity in liquid and gaseous effluents. Each report was submitted in accordance with the technical specification and was in accordance with Appendix B of Regulatory Guide 1.21 (Revision), dated June 1974. For example, the number of abnormal (unplanned or uncontrolled release of radioactive material from the site boundary) releases, including the total curies of radioactive material released, were documented in these reports, if such a release occurred. Included was a brief discussion of the release and a projected dose assessment was performed and documented, as required. No obvious omissions, mistakes, anomalous results and trends were noted.

A supplemental report, the Annual Dose Assessment to the General Public from Radioactive Effluents, contained detailed summaries of the projected dose to individuals and populations from all exposure pathways during the previous year as a result of plant operation.

Changes to the Offsite Dose Calculation Manual (ODCM) were submitted, as required in the effluent reports.

c. Conclusion

Based on the above review, the inspector concluded that the licensee effectively implemented the Technical Specifications for reporting effluent releases and dose assessment to the public and determined that the responsible personnel are dedicated and highly knowledgeable in this area.

R6.3 Management Controls

a. Inspection Scope (84570)

The inspector reviewed organization changes and the responsibilities relative to oversight of the REMP and MMP, and the Annual Radiological Environmental Monitoring Report to verify the implementation of Section 6.9.C.2 of the TS.

b. Observations and Findings

There were no major changes in the organization and responsibilities pertaining to oversight of the REMP and MMP since the previous inspection conducted in March 1995. Although titles had been changed, the reporting chain was similar to that of the previous inspection and the responsible personnel cognizant in these programs essentially remained the same.

The Annual Radiological Environmental Monitoring Reports for 1994 and 1995 provided a comprehensive summary of the results of the radiological environmental surveillance activities for the report period including a summary of the results of analysis of all radiological environmental samples and environmental radiation measurements taken from locations specified in the ODCM, results of the land use census, and an assessment of the observed impacts of the plant operation on the environment around the Pilgrim site. The results of these analyses and measurements were summarized and tabulated in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. Discussions of program deviations from the sampling schedule of Table 8.1-1 were documented in the report. These program deviations were discussed with cognizant personnel. The inspector determined that the deviations did not negatively impact the intent of the environmental sampling program.

Analytical data from 1996 were reviewed for sample frequency and analysis requirements as specified in Section 7.0 of TS. The data indicated no obvious impact to the environment public as a result of plant operation. The reports contained no omissions, mistakes, obvious anomalous results and trends.

c. Conclusion

The inspector determined that the licensee implemented very good management control and oversight of the REMP and MMP and effectively implemented Section 6.9.C.2 of the TS requirements.

R7 Quality Assurance in RP&C Activities

R7.1 Quality Assurance Audit and Surveillance Program

a. Inspection Scope (84750)

Quality Assurance (QA) Audit 95-12 Chemistry Programs and several surveillances were reviewed.

b. Observations and Findings

No deficiencies had been identified in the report; however, five recommendations had been documented for review and consideration to enhance the chemistry programs.

The audit was performed by the Quality Assurance team and was of sufficient technical depth and scope to effectively assess the quality (strengths and weaknesses) of the program.

c. Conclusions

The inspector concluded that the QA team conducted an audit of sufficient technical depth and adequately assessed the quality of the radioactive effluent control programs.

R7.2 Quality Assurance Audit Program

a. Inspection Scope (84750)

The Quality Assurance audit and surveillance reports of the REMP and MMP were reviewed against criteria contained in the Quality Assurance Department procedures, the Emergency Plan, and Regulatory Guide 1.33.

b. Observations and Findings

Audit 95-10, "Radiological Environmental Monitoring Program" dated November 13, 1995, was performed by Quality Assurance Team personnel and a technical specialist during the period October 16 - November 1, 1995. Procedure No. 18.01, "Preparation, Performance, Reporting, and Follow-up of Quality Assurance Department Internal Audits" was used as guidance. The audit scope included air sampler calibration and filter exchanges, TS and ODCM requirements, REMP procedures, sample preparation, collection and analysis, self-assessment process, and eight QAD surveillances. No findings, three recommendations, and two previously identified items were reviewed and documented.

One surveillance, Surveillance No. 96-15, "Milk Sampling," dated February 15, 1996, was conducted to supplement the next REMP audit, scheduled for October 1996. No findings or deviations were noted as a result of the surveillance.

c. Conclusion

The inspector concluded that the QA team conducted an audit of sufficient technical depth to adequately assess the quality of the radiological environmental monitoring and the meteorological monitoring programs. The audits were performed in accordance with the guidance of the procedure and Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)."

R7.3 Quality Assurance of Analytical Measurements

a. Inspection Scope (84750)

The inspector reviewed the quality assurance (QA) and quality control (QC) programs against the recommendations of Regulatory Guide 4.15, "Quality Assurance for Radiological Monitoring Programs (Normal Operations) - Effluent Streams and the Environment" to determine whether the licensee had adequate control with respect to sampling, analyzing, and evaluating data for the implementation of the REMP.

b. Observations and Findings

The inspector reviewed the "Semi-Annual Quality Assurance Status Reports" for 1995 and the first half 1996, which summarized the analytical results from the blind duplicate (split) samples and interlaboratory programs. Most of the results were within the acceptance criteria. Where discrepancies were found, reasons for the differences were investigated and resolved.

c. Conclusion

The inspector determined that the licensee continued to implement a very good quality assurance program in accordance with regulatory requirements.

P1 Conduct of EP Activities

P1.1 Emergency Preparedness Emergency Exercise (71750)

a. Inspection Scope

BECo conducted a Pilgrim station emergency preparedness exercise on October 16, 1996. The inspector reviewed the exercise scenario and observed BECo's emergency response in the operations support center (OSC) and technical support center (TSC) to evaluate emergency response organization performance. In addition, the inspector attended the subsequent formal critique presented to senior station managers on October 23 to assess the comprehensiveness of the review.

b. Observations and Findings

The annual emergency evaluated exercise was evaluated by Pilgrim evaluators and controllers. An NRC evaluation team did not witness the exercise this year, as allowed by the revised rules in 10CFR50 Appendix E. The Massachusetts Emergency Agency (MEMA) and the Massachusetts Department of Public Health (MDPH) partially participated by sending representatives to the emergency operations facility (EOF).

This year's exercise had a number of objectives in the areas of exercise planning, emergency response organization (ERO) performance, incident assessment and classification, notification and communications, and radiological consequence assessment. The scenario included a steam leak, plane crash, loss of offsite power, and loss of reactor coolant and exercised the organization through the most serious emergency classification of General Emergency. As observed in the September activation drill documented in IR 96-06, new, ORC-approved emergency plan implementing procedures were used during the exercise.

The inspector observed prompt ERO response to the OSC and TSC as evidenced by TSC and OSC activation within 30 minutes of the Alert declaration. The OSC checklist and habitability determination were performed as required by procedure EP-IP-230, OSC Activation and Response. The Emergency Plant Manager frequently briefed the OSC/TSC as plant conditions changed. The inspector also observed OSC Supervisor briefings when the task list became large. These briefings served to focus OSC coordinators on high priority

items and keep them apprised of OSC-related tasks. This observation indicated improvement from the full-participation evaluated exercise in December 1995, as documented in NRC IR 95-25, Section 8.0.

The inspector noted good communication between the Radiological Protection Coordinator in the OSC and the Radiological Supervisor in the TSC which aided timely dispatch of OSC field teams. The OSC Supervisor suggested that the craft personnel don modesty garments while waiting for task assignments to reduced the time for field team deployment. The response organization followed the new procedures well, as noted when a task was assigned to retrieve modesty garments from the plant.

The exercise critique provided a detailed review of objectives, areas for improvement and corrective action, and the identified weakness. BECo assessment of the critique was thorough and balanced. Observations made by the inspector were verified to be captured by the drill evaluators.

c. Conclusions

The 1996 Pilgrim Station Emergency Preparedness Exercise was conducted well. Observed response organization actions in the OSC and TSC were appropriate and in accordance with emergency implementing procedures. The Emergency Plant Manager and OSC Supervisor conducted timely briefings to update OSC and TSC personnel on plant conditions, emergency declarations, and task priorities and status. Good communication between the Radiological Protection Coordinator in the OSC and the Radiological Supervisor in the TSC aided timely dispatch of OSC field teams. The exercise critique was thorough and addressed both positive and negative aspects of emergency response organization performance during the drill.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

The results of the effluent controls program inspection were presented to members of licensee management on October 4, 1996. The inspector presented the environmental inspection results to members of licensee management at the conclusion of the inspection on October 18, 1996. The licensee acknowledged the findings presented at each exit meeting.

The inspectors presented the resident inspection results to members of licensee management at the conclusion of the inspection on December 11, 1996. The licensee acknowledged the findings presented.

Also, on October 3, 1996, Region I conducted an Enforcement Conference on an apparent violation related to Containment Electrical Penetrations Short Circuit Protection. BECo handouts are attached. The disposition of this matter was addressed in an NRC Letter dated October 21, 1996. The attached handouts were revised by BECo on October 7, 1996, as marked.

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 84750:	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
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 OPENED, CLOSED, AND UPDATED

<u>Opened</u>

UNR 50-293/96-08-01	Safety Evaluation Process Enhancements
VIO 50-293/96-08-02	Failure to perform survey per TS 3/4.8.A.1

<u>Closed</u>

LER 50-293/94-05	Automatic Scram Resulting From Load Rejection at 100 Percent Power
VIO EA 95-010	Primary Containment Boundary Degraded Due to Failure to Follow Calibration Procedure
IFI 50-293/96-06-01	Root Cause Analysis for "B" RBCCW Heat Exchanger Through-Wall Leak

<u>Updated</u>

None

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
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
FRV	Feedwater Regulating Valve
GL	Generic Letter
gpm	gallons per minute
HCU	Hydraulic Control Unit
HPCI	High Pressure Coolant Injection
I&C	Instrumentation and Controls
IFI	Inspection Follow-Up Item
IR	Inspection Report
IRM	Intermediate Range Monitor
ISI	Inservice Inspection
IST	Inservice Testing
LER	Licensee Event Report
MR	Maintenance Request
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NI	Nuclear Instrumentation
NOS	Nuclear Operating Supervisor
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSRAC	Nuclear Safety Review and Audit Committee
NWE	Nuclear Watch Engineer
ODCM	Offsite Dose Calculation Manual
ORC	Operations Review Committee
OSC	Operations Support Center
PEB	Pre-evolution Brief
PEC	Preliminary Evaluation Checklist
PNPS	Pilgrim Nuclear Power Station
PR	Problem Report
PRM	Plant Radiation Monitors
PWT	Post Work Test
RBCCW	Reactor Building Closed Cooling Water
RCA	Radiologically Controlled Area
RCIC	Reactor Core Isolation Cooling
RFO	Refueling Outage
RHR	Residual Heat Removal
RP	Radiological Protection
SDIV	Scram Discharge Instrument Volume
SSW	Salt Service Water
TBCCW	Turbine Building Closed Cooling Water
TP	Temporary Procedure
TS	Technical Specification
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report

ENCLOSURE 3

BECO SLIDES FROM 10/03/96

ENFORCEMENT CONFERENCE

Boston Edison Company
Pilgrim Nuclear Power Station

Containment Electrical Penetrations
Short Circuit Protection

October 3, 1996

Boston Edison

Agenda

• Introduction	E.T.Boulette
• Background	H.V. Oheim
• Root Cause and Corrective Actions	W.R.Kline
• Timeliness of Corrective Actions	W.R.Kline
• Regulatory Significance	N.L.Desmond
• Conclusions	E.T.Boulette

Boston Edison

BACKGROUND

H. V. Oheim

Boston Edison

Nature of Technical Concern

- Electrical penetrations form part of primary containment pressure boundary
- Pressure seal is epoxy resin seal of conductors
- Protection from over heating provided by short circuit and overload protection
- Circuit breakers in circuits of concern were magnetic-only (short circuit), contactors open on thermal overload (heater for thermal overload relay)
- Short circuit and overload protection were not properly coordinated to fully protect penetration

Boston Edison

Issue is Relatively Low Risk

- Circuit breakers in question are Westinghouse HFB magnetic-only, set between 300 & 400 amps
- 12 motors for drywell cooler fans with Size 1 starters, 10 HP motors
- Vendor catalog specifies setting at $\leq$ 182 amps for the 10 HP motors

Boston Edison

Issue is Relatively Low Risk

- Potential problem would be a sustained, high impedance fault between 182 and 300/400 amps
- Could damage starter contactor (prevent overload trip) and circuit breaker trip coil (prevent short circuit trip)
- Result would be excessive conductor temp. (4-8 sec. in normal ops, 2-4 sec. in accident conditions)

Boston Edison

Revised 10/2/96 (next page)

10/02/1996

Boston Edison Company
Pilgrim Nuclear Power Station

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Timeline Of Events

- July 9, 1991 PCAQ 91-152 (PR 91.2151)
  - As a result of self-assessment, identified PS-74 did not address penetration protection for all possible current conditions (full load, overload, short circuit)
  - Later closed to PCAQ 91-165

Boston Edison

Timeline Of Events (cont)

- July 22-26, 1991 EDSFI

Relative to this issue NRC noted:
- No coordination curves for penetrations available, could not prove protection
- Cables and penetrations were derated for normal operations, worse case accident conditions not evaluated
- Overload settings for cables (in PS-74) were high

Boston Edison

Timeline Of Events (cont)

- July 31, 1991 PCAQ 91-165 (PR 91.2165)
  Short circuit protection for penetrations must be verified against conductor I^2t
- August 1, 1991
  Coordination curves for 9 selected penetration circuits showed proper protection. Study evaluated largest protective device for each size conductor. Formed basis for Operability Evaluation of 8/1/91.
- August 6, 1991 PCAQ 91-167 (PR 91.2167)
  - Documented EDSFI findings (UNR 91-80-04)
  - Closed to resolution of PCAQ 91-165

Boston Edison

Timeline of Events (cont)

- 1992
  - Engineering completed calculations PS-119, 122, and 124 evaluating penetration protection
    - PS-119 evaluated protection under normal operations
    - PS-124 evaluated accident conditions
  - Calculations noted band between thermal and short circuit protection
  - PS-74 retired

Boston Edison

Timeline of Events (cont)

- July 13, 1993 PCAQ 91-165 closed
  - Closure based on approval of SJA 93-006 [LTP item 639] to implement modifications recommended in PS-119
  - Modifications referred to as enhancements
    - Transfer some circuits to spare, larger penetration conductors
    - Replace some breakers and fuses
    - Add fuses
    - Change trip settings for some magnetic-only breakers

Boston Edison

Timeline of Events (cont)

- August 19, 1993 NRC closed UNR 91-80-04
  - Closure based on review of PS-119 and PS-124
  - Additional modifications planned

Boston Edison

(Revised next page) 10/2/96

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Timeline of Events (cont)

- January 1996
  - Results of GE analysis of containment response to 75° F service water temperature showed drywell temperature profile was higher than previous analysis (PR 96.9028)
    - Included review of PS-124 (accident conditions)
- February 7, 1996 PR 96.9048
  - Operator found circuit breaker 52-1834 for a drywell cooler fan tripped
  - Breaker would not reset
  - Fan motor found failed

Timeline of Events (cont)

- March - April 1996
  - Penetration calculations reworked to address containment temperature issues
  - Temperature rise of conductors for LOCA was a concern
  - Inspection of failed drywell fan circuit found fused contactor
  - Concern spread to penetration circuit breakers with magnetic-only settings

Timeline of Events (cont)

- April 9, 1996 containment declared inoperable and 24 hour LCO entered per Technical Specifications (PR96-9169)
  - 10 circuit breakers for Size 1 starters set to LOW (minimum) setting
  - LCO was exited

Timeline of Events (cont)

- April 10, 1996 to date
  - 12 circuit breakers were replaced with thermal-magnetic breakers (completed by April 23, 1996)
  - LER 96-004 documented the event (May 9, 1996)
  - Extensive root cause conducted per FPI methodology (August 14, 1996)
  - 10 additional breakers replaced to improve protection

Actions To Complete

- Replace additional circuit breakers (2 of 24)
- RFO#11 modifications (from LTP)
  - Approximately 30 mods
    - Breaker changes
    - Wire changes
    - Addition of fuses

Root Cause & Corrective Action

W. R. Kline

Timeline of Events (cont)

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Boston Edison

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Boston Edison

Root Cause & Corrective Action

W. R. Kline

Boston Edison

Root Cause

- Areas identified as contributors
  - Human Factors
  - Procedure Quality
  - Supervision
  - Training
- Corrective actions
  - Taken
  - Planned

Boston Edison

Root Cause Overview

- Primary Root Cause
  - Mischaracterization of modifications as enhancements
    - Should have been handled as corrective actions
- Contributing Causes
  - Vendor requirements not properly identified
  - Calculation summary not complete
  - Supervision did not ensure actions to be taken were properly reflected in Problem Report
  - Failure to follow Long Term Plan (LTP) procedure
  - Procedure training not effective

Boston Edison

Calculation Conclusions

- Adequate - normal circuit loads
- Conductor ampacities below protective device trip current for some circuits
- Inadequate short circuit protection on some circuits
  - Overload and short circuit protection not coordinated per National Electric Code (NEC)

Boston Edison

Characterization As Enhancements

- General nuclear philosophy in 1992
  - Set protective trip setting high enough to ensure protective action
    - Example: starting current for safety related valves
- Funding requested in 1993
  - Install PS-119 modifications
  - Assigned number LTP 639
  - Lack of breaker coordination identified
  - Listed as recommended actions in conceptual SJA
  - Approved without immediate funding

Boston Edison

Human Factors Issues

- Calculation not complete
  - Coordination problem identified in body of calculation not provided in calculation summary
  - Breaker vendor requirements not properly identified
  - Some breaker coordination not in accordance with NEC
- NOP89A1 "Long Term Plan" not followed
  - Detailed planning and estimating SJA not prepared
  - Budget request not submitted
  - PDC never prepared
  - Completion date never established

Boston Edison

Procedure Quality Issues

- NOP89A1 confusing and difficult to use
- Tracking system not effective
- Semi-annual review of LTP not completed for Schedule C items

Boston Edison

(Revised next page) 10/2/96

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- Engineering response to PR 91.2165
  - Did not clearly identify corrective actions
  - Changes recommended as enhancements
- Resulted in PR closure to LTP 639

Boston Edison

Training Issues

- No formal personnel training for NOP89A1
- Personnel not familiar with follow-up actions after initial approval
  - Request for funding not completed
  - Planned completion date not established

Boston Edison

Corrective Actions Taken

- April 1996
  - Primary containment LCO entered
  - 10 Breakers reset to clear LCO
  - 12 Breakers replaced post-LCO (by April 23)
- LER 96-004 submitted
- Root cause investigations initiated
- LTP review
- 10 additional breakers replaced to date

Boston Edison

Revised 10/3/96 (attached)
[illegible]

Corrective Actions Planned

- Complete remaining modifications by RFO 11 to complete LTP 639
- Revise NOP89A1 after detailed review
- Establish improved tracking mechanism for periodic LTP review
- Revise calculation procedure to require verification that corrective actions are tracked
- Review other calculations to determine if similar conditions exist
- Electrical engineering design guide will be reviewed for improvement

Boston Edison

Revised 10/3/96 (attached)
[illegible]

Planned Training

- Communication of potential issues
- Importance of calculation summaries
- Refamiliarize personnel with LTP process
- Formal training on NOP89A1

Boston Edison

Timeliness of Corrective Action

W. R. Kline

Boston Edison

(Revised next page) 10/3/96
[illegible]

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  - The initial root cause only covered the technical issue. Management review and discussions on the completed initial root cause resulted in request for Independent Oversight Team (IOT) Leader review of timeliness issue using FPI root cause methodology.

Corrective Actions Taken

- Root cause of timeliness issue by IOT Leader (July 8 - July 31)
- LTP review (Sept. 26)
- EDSFI action items reviewed (Sept. 27)
- Revised root cause on technical issue completed (Oct. 1)
- 10 additional breakers replaced (by Oct. 3)

Corrective Actions Planned

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Timeliness: 1991-1993

- PCAQ identified potential problem
- Initial analysis was timely-1992
- Low probability situation identified
- Characterized as enhancement
- Initial actions to fund modifications taken

Boston Edison

Timeliness: 1993-1995

- Failure to follow LTP process
  - Not timely in funding and scheduling modifications for installation
- Included modifications in RFO#11 work scope

Boston Edison

Timeliness 1996

- Timely declaration of LCO
- Prompt restoration of operability
- Accelerated replacement of 12 Breakers
- Improved design with thermal magnetic type breakers

Boston Edison

Summary

- Mischaracterization of modifications
- Follow up to PS-119 findings during 1993 -1996 not timely
- Appropriate action taken - 1996
- Improvements to be completed
  - Human factors
  - Procedures
  - Supervision
  - Training

Boston Edison

REGULATORY SIGNIFICANCE

N. L. Desmond

Boston Edison

Issue Was Self-identified

- Identified technical issue in April 1996
  - Found during review of other issues
    - Elevated seawater temperature
    - Tripped drywell cooler fan
    - Fused contactor
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Boston Edison

(Revised next page) 10/3/96

Timeliness of Corrective Action

W. R. Kline

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REGULATORY SIGNIFICANCE

N. L. Desmond

Potential Safety Significance Reviewed

- Primary containment was not challenged
  - Decision to enter containment LCO
- Low probability scenario requires:
  - High impedance electrical fault
  - Currents in the susceptible range
  - Condition fails to degrade to breaker setpoint

Boston Edison

Prompt Action Taken

- Entered 24 hour LCO
- Lowered 10 breaker settings
- Completed inspection of containment penetration
- Replaced 12 breakers by April 23, 1996
- Replaced 10 additional breakers by September 30, 1996
- Remaining modifications scheduled by end of RFO#11
- Completed LTP item review
- Review of other EDSFI findings completed

Boston Edison

Comprehensive Preventive Action Planned

- Long term planning process improvements
- Review of other calculations
- Electrical engineering design guide will be revised to expand on electrical penetration protection and coordination of overload/short circuit protection

Boston Edison

Conclusions

- Inappropriate timeliness
- Comprehensive corrective action being taken
- Significance understood

Boston Edison

(Revised next page) 10/3/96

[illegible]

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