September 14, 1995

Ms. Jane Fleming
8 Oceanwood Drive
Duxbury, MA 02332

Dear Ms. Fleming:

In reference to our conversation this morning, I have enclosed two Inspection Reports dealing with Pilgrim Shutdown Margin Test. If you have any questions or comments please contact me at (301) 415-3036.

Sincerely,

Original signed by:
Ledyard B. Marsh, Director
Project Directorate I-1
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket No. 50-293

Enclosures: 1. Inspection Report 50-293/95-09
2. Inspection Report 50-293/95-13

DISTRIBUTION w/o encls:
Docket File
PUBLIC
PDI-1 Reading
SVarga
JZwolinski
LMarsh
SLittle
REaton

DOCUMENT NAME: G:\MARSH\Fleming.ltr
To receive a copy of this document, indicate in the box: "C" = Copy without attachment/enclosure "E" = Copy with attachment/enclosure "N" = No copy

OFFICE	PDI-1:LA		PDI-1:PM		PDI-1:D	E				
NAME	SLittle		REaton		LMarsh					
DATE	9/14/95		9/14/95		9/14/95					

OFFICIAL RECORD COPY

9509200265 950914
PDR ADOCK 05000293
G PDR

DF01

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

September 14, 1995

Ms. Jane Fleming
8 Oceanwood Drive
Duxbury, MA 02332

Dear Ms. Fleming:

In reference to our conversation this morning, I have enclosed two Inspection Reports dealing with Pilgrim Shutdown Margin Test. If you have any questions or comments please contact me at (301) 415-3036.

Sincerely,

LBMarsh

Ledyard B. Marsh, Director
Project Directorate I-1
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket No. 50-293

Enclosures: 1. Inspection Report 50-293/95-09

2. Inspection Report 50-293/95-13

June 21, 1995

Mr. E. Thomas Boulette, PhD
Senior Vice President - Nuclear
Boston Edison Company
Pilgrim Nuclear Power Station
Rocky Hill Road
Plymouth, Massachusetts 02360

SUBJECT: NRC INSPECTION REPORT NO. 50-293/95-09 AND NOTICE OF VIOLATION

Dear Mr. Boulette:

From April 4 to May 16, 1995, Messrs. R. Laura and A. Cerne of this office led resident inspector and region based safety inspections at the Pilgrim Nuclear Power Station, Plymouth, Massachusetts. Areas relevant to the health and safety of the public examined during this inspection are described in the enclosed report. Our findings were based upon observations of performance and independent evaluations of safety systems and quality records. The preliminary results have been discussed with you and other members of your staff at an interim public exit meeting held on April 11, 1995 at the Chiltonville Training Center.

We observed the substantial progress made in inspecting and upgrading major plant components during refueling outage no. 10 that collectively assure or improve safety at the Pilgrim Nuclear Power Station (PNPS). Some examples include: (1) installation of the core shroud pre-emptive repair, (2) installation of a new and upgraded control room alarm system with diverse and redundant power supplies, (3) new and upgraded low pressure turbines and casings, (4) reactor vessel beltline weld inspections using the latest ultrasonic technology, (5) significant progress in the area of motor operated valves including the completion of the phase I static and dynamic testing and progress in installing pressure locking modifications, (6) new 125 volt, DC, safety-related battery banks. We recognize the challenging outage work scope that required extensive coordination and management oversight to implement. Lastly, operators moved numerous fuel assemblies without incident during the two fuel movement periods.

Based on the results of our inspection, we identified one violation of regulatory requirements concerning the control of special nuclear material (SNM), as specified in the enclosed Notice of Violation (Notice). Your search plan effectively located the two nuclear detectors that inadvertently left PNPS and were found at a nuclear laundering facility located in Springfield, MA and a nuclear waste processor located in Oak Ridge, TN. No threat to public safety existed because the detectors contained very low amounts of Uranium-235 and remained in the nuclear waste stream. However, a review of your SNM operating experience found other instances of a lack of sensitivity towards the control of portable, non-fuel SNM. Your comprehensive search plan resulted in approximately 115 millirem of radiation worker exposure and also an individual contamination. Additionally, the search effort consumed

9506280610 4pp

Enclosure 1

approximately 4000 manhours, which had the potential to be a distraction to management during the major refueling outage.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. Please specifically address your evaluation of the need to physically audit the portable SNM stored in the spent fuel pool, especially since this SNM has only been audited through paperwork during the last 5 years. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

Some other opportunities for improvement were identified as a result of our inspections. Engineering management attention is needed to provide the appropriate design guidance and procedural infrastructure for digital upgrade modifications. Also, the apparent lack of management aggressiveness in remedying a buzzing sound that originated from the "A" emergency diesel generator set during the last three years is considered a weakness. Our electrical specialists in Region I are reviewing your after-the-fact operability determination to determine the proper regulatory disposition of this issue. The outage as-low-as-reasonably-achievable (ALARA) and radiation worker contamination goals were exceeded. Lastly, the maintenance staff had to rework a control rod drive system common minimum flow isolation valve, which required the use of a freeze seal and welding in a contaminated and radiation area, due to the lack of a pre-installation shop leak test.

The responses directed by this letter and enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96.511. Your cooperation with us is greatly appreciated.

Sincerely,

ORIGINAL SIGNED BY:

James Linville, Chief
Projects Branch No. 3
Division of Reactor Projects

Docket No. 50-293

Enclosures:
1. Notice of Violation
2. NRC Inspection Report No. 95-09
3. BECo Handouts of the May 11, 1995 Meeting with the NRC

cc w/encls:
L. Olivier, Vice President - Nuclear and Station Director
T. Sullivan, Plant Department Manager
R. Fairbank, Manager, Regulatory Affairs and Emergency Planning Department
D. Tarantino, Nuclear Information Manager
D. Ellis, Acting Senior Compliance Engineer
R. Hallisey, Department of Public Health, Commonwealth of Massachusetts
The Honorable Therese Murray
The Honorable Linda Teagan
B. Abbanat, Department of Public Utilities
Chairman, Plymouth Board of Selectmen
Chairman, Duxbury Board of Selectmen
Chairman, Nuclear Matters Committee
Plymouth Civil Defense Director
Paul W. Gromer, Massachusetts Secretary of Energy Resources
Bonnie Cronin, Legislative Assistant
A. Nogee, MASSPIRG
Regional Administrator, FEMA
Office of the Commissioner, Massachusetts Department of Environmental Quality Engineering
Office of the Attorney General, Commonwealth of Massachusetts
T. Rapone, Massachusetts Executive Office of Public Safety
Chairman, Citizens Urging Responsible Energy
D. Screnci, PAO (2 copies)
NRC Resident Inspector
Commonwealth of Massachusetts, SLO Designee

<u>Distribution</u> w/encls:
Region I Docket Room (with concurrences)
PUBLIC
Nuclear Safety Information Center (NSIC)
R. Conte, DRP
J. Shedlosky, DRP
M. Kalamon, DRP

<u>Distribution</u> w/encls (**VIA E-MAIL**):
T. Marsh, NRR
R. Eaton, NRR
W. Dean, OEDO
Inspection Program Branch, NRR (IPAS)

DOCUMENT NAME: A:PIL9509.INS
To receive a copy of this document, indicate in the box: "C" = Copy without attachment/enclosure "E" = Copy with attachment/enclosure "N" = No copy

OFFICE	RI:DRP		RI:DRP		RI:DRP		/	
NAME	Laura/meo		Conte		Linville			
DATE	6/6/95							

OFFICIAL RECORD COPY

ENCLOSURE 1

NOTICE OF VIOLATION

Boston Edison Company
Pilgrim Nuclear Power Station

Docket No. 50-293
License No. DPR-35

During an NRC inspection conducted on April 4, 1995 through May 16, 1995 a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C, the violation is listed below:

10 CFR 70.51(b)(1) requires that records will be kept showing the receipt, inventory (including location), disposal, acquisition, and transfer of all special nuclear material.

Contrary to the above, on March 29, 1995, Boston Edison Company (BECo) did not possess records showing the location and transfer of six nuclear detectors. Additionally, on April 6, 1995, a fuel loading chamber was also found missing. As a result of an extensive search effort, all seven pieces of the missing special nuclear material were located, with two of the seven missing nuclear detectors located offsite.

This is a Severity Level IV violation (Supplement III).

Pursuant to the provisions of 10 CFR 2.201, Boston Edison Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555 with a copy to the Regional Administrator, Region I, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

Dated in King of Prussia, Pennsylvania
this 21st day of June, 1995

U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.: 50-293

Report No.: 95-09

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

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: April 4 - May 16, 1995

Inspectors: R. Laura, Senior Resident Inspector
A. Cerne, Resident Inspector
K. Battige, Engineer, NRR
T. Shedlosky, Project Engineer,DRP
J. Caruso, Operations Engineer, DRS
J. Noggle, Senior Radiation Specialist, DRSS
R. Bores, Chief, Facilities Radiation Protection Section
C. Beardslee, Mechanical Engineer, DRS
B. Korona, Reactor Engineer, DRS
J. Calvert, Engineering Branch, DRS
S. Wittenberg, Instruments & Controls Branch, NRR

Approved by: ORIGINAL SIGNED BY: 6/19/95
R. Conte, Chief — Date
Reactor Projects Section 3A

Scope: Safety inspections were conducted in the areas of plant operations, maintenance and surveillance, engineering, plant support, and safety assessment and quality verification. Initiatives selected for review included a detailed review of refueling operations, maintenance field performance, core shroud pre-emptive repair, and the digital upgrade made to the reactor recirculation pump speed controllers. Reactive inspections were conducted in the areas of special nuclear material, shutdown margin demonstration test that yielded unexpected results, and two events involving inappropriate control rod movements.

Findings: One violation was identified concerning inadequate control of special nuclear material. Two unresolved items were identified involving the timeliness of corrective action to address a buzzing sound originating from the "A" emergency diesel generator and the quality of the safety evaluation for the digital upgrade made to the reactor recirculation pump speed controllers. Overall performance during this six week period is summarized in the Executive Summary.

~~9506280615~~ 49pp

EXECUTIVE SUMMARY

Pilgrim Inspection Report 95-09

Plant Operations: Operators moved reactor fuel assemblies during the two fuel movement periods in a meticulous manner without incident. Operator identification and response to equipment problems such as the erratic readings of the "B" source range monitor and sluggish operation of the grapple airline take-up reel demonstrated a strong safety perspective. This was exemplified when control room operators acted decisively and correctly to terminate a shutdown margin demonstration test due to unexpected reactivity results. Operations section management developed a detailed and methodical recovery plan. One area in need of improvement was self-disclosing when operator errors resulted in two different inappropriate control rod movements. Plant management stopped refueling operations to develop a detailed recovery plan, emphasize with the operators the need to do-the-job-right-the-first-time approach, increase the management oversight of refueling activities, and enhance procedural controls for control rod latching and venting.

A safety system walkdown of the augmented fuel pool cooling line-up found the system was properly configured with valves and breakers in the proper positions.

Maintenance and Surveillance: Overall, the maintenance staff effectively completed numerous maintenance activities during the outage. Workers were qualified, supervisory oversight was generally evident, and work package quality was proper. Some noteworthy observations include extensive prefabrication and use of heat shrinkable tubing during the scram pilot valve assembly change-outs. Instrument and controls (I&C) workers coordinated work well with mechanical maintenance who changed the diaphragms on the scram inlet and outlet valves. The maintenance staff responded well to the major emergent work on the "A" emergency diesel generator (EDG) stator and rotor, which were removed and sent out to a vendor for refurbishment.

Some opportunities for improvement were identified. Workers were slow to maintain work package verification signatures up-to-date. Also, on one occasion, I&C technicians were observed using an out-of-date electrical print (without adverse effects) during a post work testing activity on the "A" EDG. A control rod drive system minimum flow, common isolation valve had to be reworked, which required the use of a freeze seal and work in a radiation and contaminated area, due to the lack of a prework shop leak test. Lastly, maintenance section management has not yet developed an effective set of performance indicators to trend performance.

Two instances of poor work control, one NRC identified and one licensee identified, indicate that increased attention-to-details is required prior to major train swaps. Both examples involved the "A" EDG including a missed degraded voltage surveillance test and the decision to remove the "B" core spray system from service before the "A" EDG was declared operable to support the operability of the "A" core spray system. For both cases, BECo completed after-the-fact evaluations concluded that no violations occurred and the NRC staff acknowledged the results.

(EXECUTIVE SUMMARY CONTINUED)

Engineering: It was evident that considerable effort was spent preparing for the augmented reactor pressure vessel (RPV) examination as evidenced by the pre-outage review of RPV stresses, fatigue life, and flaw tolerances, in the performance of two access studies, and the digitization of vessel radiographs in preparation for flaw evaluation. Personnel involved in conducting the examination and evaluating the data were very knowledgeable of the procedural requirements, ultrasonic (UT) equipment and techniques, and evaluation methods. Very few flaws were identified, and all were determined to be acceptable per American Society of Mechanical Engineers (ASME) Code acceptance standards. The issue concerning completeness of the examination (i.e. total weld coverage) will be resolved through future BECo communications with the NRC Office of Nuclear Reactor Regulation.

Level 1 enhanced visual (EVT1) examinations to support the core shroud pre-emptive repair were performed by qualified personnel, in accordance with the procedure and commitments made to the NRC. No relevant indications were identified in the vertical or gusset welds. Through the visual inspection review process, substantial observations were made which increased the effectiveness and quality of the EVT1 examinations. Nonconformance reports initiated during the core shroud repair project contained good technical justifications for proposed resolution, and this approach and control were found good initiatives and strengths of this organization. Receipt inspections were performed in accordance with the level of review necessary for individual components. Good BECo quality assurance oversight of the vendor's quality assurance department personnel was observed.

Overall, the engineering for the recirculation pump speed control digital upgrade modification was performed with due regard for plant safety and reliability. Because of the conservative approach to the analog-to-digital upgrade, the weaknesses identified by the inspector should not impair system performance. However, opportunities for improvement existed in the area of appropriate guidance and procedural infrastructure for digital upgrade modifications.

During refueling outage no. 10, BECo found loose laminations caused the buzzing sound originating from the "A" EDG stator for the last three years. This anomaly had the potential to result in an inoperable diesel generator. Management was slow to evaluate and resolve the buzzing sound. Further, no operability evaluation was performed nor were performance based actions taken such as an electrical flux test or boroscopic examination.

Plant Support: A loss of control of special nuclear material resulted in two nuclear detectors inadvertently leaving the site. Although the search plan found all missing SNM, a violation was identified because of repetitive problems on site in this area. At no time was public safety in jeopardy since the detectors contained low amounts of Uranium-235 and remained in the nuclear waste stream. Indications of previous problems were evident in this area.

The radiological control program was well managed, with good health physics resources devoted to protection of the workers. External and internal dose

(EXECUTIVE SUMMARY CONTINUED)

tracking was reviewed and found to be accurate and complete. Radiation protection coverage of outage work activities was of good quality, but a weakness was noted in the quality of the radiological controls specified in radiation work permits. The ALARA (as low as reasonably achievable) program performance was good. Some significant shielding efforts were evident, however, better follow-through could have resulted in better exposure reduction results. Also, the value of exposure reduction considerations was often limited in scope, and some additional exposure reduction opportunities were overlooked. The problem report program was excellent in identifying station radiological problems, however, corrective actions were not always effective. Additionally, the licensee was slow to resolve an occupational safety concern reported by the inspector.

The security staff performed well during the outage activities including positive control of the drywell and the compensatory measures watch established for the "A" EDG work.

Safety Assessment/Quality Verification: Plant management provided extensive oversight over the RF010 activities including field observations. Discussions held at the plant managers morning meeting emphasized the minimization of shutdown risk, radiological performance, and clearly focused on reactor plant safety. For example, management decided to replace all scram pilot valves rather that replace some periphery ones during power operations. Also, management decided to perform a detailed ultrasonic examination of indications in the weld on the 0 degree core shroud access cover even though an enhanced visual inspection showed no observable depth of the indication. The stoppage of refueling operations to develop lessons learned from two control rod events represented a strong management action. Plant workers initiated numerous problem reports to document issues to obtain corrective actions. Critiques were held in a timely manner to establish the preliminary sequence of events, immediate corrective actions, and significance level.

A 10 CFR 59.59 safety evaluation for the core shroud pre-emptive repair determined that an unreviewed safety question did not exist.

TABLE OF CONTENTS

Table of Contents

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

At the start of the report period, Pilgrim Nuclear Power Station (PNPS) was in the refuel mode of operation with the reactor vessel head removed and fuel shuffle (movement) no. 1 in progress. Fuel shuffle no. 1 was completed, the core shroud pre-emptive repair installed, and the reactor vessel weld inspections were completed. Fuel shuffle no. 2 was completed and the internals (moisture separator and dryer) were placed back in the vessel. The period ended with vessel reassembly completed with the installation of the vessel head and preparations in progress to torque the vessel head nuts. The next major planned milestone was the vessel hydrostatic test.

2.0 PLANT OPERATIONS (60710, 71707, 93702, 92901)

2.1 Plant Operations Review

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

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

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

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

2.2 Refueling Activities

The inspector observed portions of fuel movements made during fuel shuffles no. 1 and 2. Observations were made locally at the refueling bridge and remotely in the control room. Reactor fuel remained loaded during the refueling outage (RFO-10). Fuel shuffle no. 1 involved a total of 419 movements of fuel assemblies and double blade guides. After installation of the core shroud pre-emptive repair, fuel shuffle no. 2 involved a total of 578 movements of fuel assemblies and double blade guides. 136 fuel assemblies of the total 580 were replaced with new assemblies. The inspector observed that operators generally moved fuel assemblies in one direction at a time. Very good coordination of the fuel movements was evident between the refueling bridge crew and the control room operators. The inspector witnessed management tours of refueling floor and control room activities. Fuel movements were performed in a meticulous manner without incident.

Operators acted conservatively and demonstrated a proper safety perspective by identifying problems and initiating corrective action at an earlier stage. For example, operators immediately stopped fuel movements in the respective core quadrant when the "B" source range monitor (SRM) became inoperable as a result of anomalous readings. After maintenance technicians replaced and calibrated the "B" SRM detector, operators recommenced fuel movements. Another example of excellent operator awareness involved the improper operation of the refueling mast air supply line take-up reel. The air supply line was not winding properly on the take-up reel and could have become tangled in the mast. After the take-up reel was repaired by maintenance technicians, operators recommenced fuel movements.

Extensive planning and coordination was required for the reactor vessel beltline inspection, core shroud pre-emptive repair modification, in-vessel visual inspection, 20 control rod exchanges, 15 control rod drive replacements, and fuel movements. Due consideration was given for heavy lifts over the reactor core, secondary containment integrity and foreign material exclusion. Plant management discussed the progress of refueling activities including the evaluation of emergent issues at the morning plant managers meeting. Shutdown risk was effectively managed through the use of compensatory measures established pursuant to temporary procedure 95-010. Also, the operations section manager provided a detailed shutdown safety review and protected/available equipment status at each morning meeting. An outage lessons learned meeting is scheduled to be held at the completion of the outage to develop lessons learned for the next refueling outage.

An opportunity for improvement became self-disclosing during venting and latching of control rods. BECo initiated a control rod shuffle program during RFO10. A combination of operator errors and weak programmatic controls resulted in two inappropriate actions. The first event occurred on April 21, 1995 when control rod 22-35 was inadvertently inserted without a blade guide in place. The senior reactor operator in charge did not have the correct information on the location of the open fuel cells. The inspector held discussions with the operators involved. Also, the operator stationed on the refueling bridge informed the control room that the cell did not have a blade guide installed. However, the senior reactor operator stationed locally at the hydraulic control unit, where a temporary pump was used as a pressure source, did not receive this information from the control room. No adverse safety consequence resulted to control rod 22-35. The rod was held with a J-hook from the refueling bridge as the rod was withdrawn. Operations section management held a critique and initiated a problem report to further evaluate and develop longer term corrective actions.

A second control rod event occurred on April 30, 1995 during the venting and latching of control rod 18-35, which jammed against an improperly positioned double blade guide. The refueling bridge operator stationed to ensure the double blade guide does not lift up as the rod was inserted did not identify the anomaly because he moved the bridge over the spent fuel pool to start an unrelated activity. The plant manager stopped refueling operations to develop a detailed recovery plan to free the stuck rod, conduct meetings with all operations personnel to stress the need for increased attention to details, and to implement a more rigorous management self assessment (oversight) process. Contributing to this decision to stop refueling operations was the control rod event discussed above that occurred on April 21, 1995 and also an inadvertent start of the "A" emergency diesel generator that occurred on April 24, 1995.

Operations section management held a critique and initiated a problem report. The inspector viewed several videotapes that detailed the area where the rod jammed against the blade guide. Operators freed the blade guide from the cell using an approved temporary procedure. A fuel cell inspection identified an indication on control rod 18-35 that was approximately 1/2 inch long by 10 mils high. As a result, BECo removed and replaced the potentially damaged control rod. The inspector determined that no adverse safety consequence resulted form the stuck rod. The procedural controls in procedure 2.2.87, attachment 12 were enhanced. The inspector determined that the corrective actions, including the stoppage of all refueling activities, instituted rigorous controls for control rod latching and venting activities.

Overall, operators performed well during the refueling operations associated with RFO10. For example, fuel assemblies were moved in a deliberate manner without incident. Also, the operator identification and response to the "B" SRM and air-line take-up reel equipment anomalies represented an excellent safety perspective. One area in need of improvement involved the procedural controls and operator attention-to-details during control rod venting and latching operations. The inspector considered the management decision to temporarily stop refueling operations, after the April 30, 1995 event, to be a strong management action.

2.3 Shutdown Reactivity Margin Demonstration

Operators conducted the post fuel load shutdown margin test on May 8, 1995. Operators terminated the test prior to completion and inserted the two control rods being manipulated, in response to indications that the reactor was reaching the onset of criticality. Subsequent review determined an error in the vendor supplied core reactivity design calculations.

The test was intended to demonstrate that the reactor would be subcritical with a reactivity margin of 0.25 %Δk (short for percent $\Delta k/k$) at any time in fuel cycle 11, with the strongest control rod fully withdrawn. The related surveillance requirements are described in Technical Specification 4.3.A.1, and are required to be demonstrated following reactor core alterations. The basic strategy of this test is to fully withdraw the strongest control rod having a diagonally adjacent rod partly withdrawn to a position calculated to insert at least R + 0.25%Δk in reactivity. The value of R in %Δk is the amount by which the core reactivity at any time in the operating cycle is calculated to be greater than at the time of the demonstration test due to the combined effect of poison and fuel burn up. Additional corrections are applied because the test is normally performed at a higher temperature than the assumed cold condition of 68°F and also an allowance for inverted boron carbide (B_4C) tubes within control rod blades. This allowance compensates for the loss of reactivity worth in control rods that may have gaps in poison material at the tops of control rod blades due to poison depletion. An inverted poison tube is assumed to result in a space within the tube that was designed to be filled with boron carbide.

To support the test conducted on May 8, General Electric Company's Nuclear Fuel Division calculated a cold shutdown margin for reload 10, fuel cycle 11 as 1.49%Δk. This value reflected revised calculations for a moderator temperature of 68°F, R-factor, and inverted B_4C allowance.

The inspector reviewed data and calculations from the rod-adjacent demonstration that was performed in accordance with Pilgrim Station Procedure 9.16. The test was to conclude with the strongest control rod, the object rod, 10-35, at notch position 48 and the adjacent margin rod, 14-31, at notch position 22. Reactor moderator temperature was 86°F. The test was terminated by the Operations Department personnel and all control rods inserted after the object rod was withdrawn to position 34 with the margin rod at 22, because of evidence of source range multiplication and the onset of a critical reactor condition. A Problem Report, 95.9270, documented the issue.

General Electric calculated the demonstrated shutdown margin for control rod 10-35 at notch position 48 based on the observed core configuration assuming the reactor critical with 10-35 at position 34 and 14-31 at position 22. It was calculated as 0.51%Δk. The error in reload 10, cycle 11 cold core shutdown margin was therefore approximately 1.0 %Δk too high.

BECo personnel reran the shutdown margin demonstration test using revised core reactivity design value and a less conservative moderator temperature of 90°F instead of 100°F and removed two notch positions of conservatism, positioning the margin rod at notch 18 instead of notch 22. The change in temperature correction reduced the requirement for demonstrated shutdown margin to be 0.38%Δk in order to verify the technical specification requirement of 0.25%Δk. This test was rerun on May 9. In that configuration with the object rod, 10-35 at position 48, and the margin rod at notch 18, the margin was 0.42%Δk at 87°F moderator temperature.

In order to increase their confidence BECo requested that General Electric Company identify other strong rod combinations for additional shutdown margin demonstration tests. In the first of these, the object rod was identified as 30-11 and the margin rod, 26-15. The required shutdown margin to demonstrate the technical specification was 0.39%Δk. The test satisfied this requirement by demonstrating a margin of 0.42%Δk with reactor moderator temperature of 87°F. In the second test, the object rod was identified as 38-43 and the margin rod, 34-39. The required shutdown margin to demonstrate the technical specification was 0.40%Δk. The test satisfied this requirement by demonstrating a margin of 0.43%Δk with reactor moderator temperature of 85°F.

The inspector reviewed the data and calculations performed by both BECo and General Electric and discussed potential causes for the core design error with BECo personnel. There appears to have been an error of approximately 1.0 $\%\Delta k$ in the assumed cold core "eigenvalue," a measure of the difference between design and actual core. These are predictions of required reactor core reactivity made by the design organization for the next operating cycle. They are made for both the cold critical and also the hot at power conditions and are based on data provided from the last operating cycle. BECo provides General Electric with critical operating data during the operating cycle which allows the core design organization to monitor and compare their predications for the reactor core hot at power "eigenvalue" with the observed critical conditions. However, far less cold critical data is available. General Electric indicated that they expect larger errors with local, rod-adjacent, shutdown margin demonstrations compared to in sequence critical demonstrations. A licensee representative reported to the inspector that in-sequence criticality performed at the end of the refueling outage in accordance with Pilgrim Station procedure 9.16.1, should provide confirmatory core design data.

At the time of this inspection, General Electric was verifying their design calculations to assure better agreement during the in sequence criticality test and hot full-power operations. BECo has requested that General Electric Company's Nuclear Fuel Division inform them of the results of their analysis.

In conclusion, the inspector found that BECo control room operations personnel acted decisively and correctly in terminating the original demonstration test. Additionally, they took appropriate response actions, analyzed the unexpected test results, verified that the technical specification requirements were met and performed the test through completion. They also gained confidence in the test results by testing other control rod combinations. BECo has also taken action to task the core designer to complete a failure analysis and core design verification. Operator performance was good; and overall, the licensee's past event response to this was appropriate.

2.4 Safety System Walkdown - Augmented Fuel Pool Cooling (Mode 2)

The inspector conducted a safety system walkdown of the fuel pool cooling system (FPC) in the augmented fuel pool cooling (AFPC) mode of operation to verify its operability. The inspection included the following: 1) determination of whether the system lineup procedure matched plant drawings, the as-built system configuration, and the system as described in the Final Safety Analysis Report (FSAR); 2) inspection of system material condition; 3) verification that instrumentation was properly installed, currently calibrated and functioning, and process parameters were consistent with normally expected values; 4) verification that valves in the flow path were in the correct position as required by procedure; and 5) verification of proper breaker positions at local electrical boards. In addition, the inspector observed a residual heat removal system (RHR) loop swap which affected the lineup for AFPC.

The inspector compared the normal FPC and AFPC lineup checklists, plant drawings, as-built configuration, and the system as described in the FSAR and verified that they correlated. During the walkdown, the normally installed instrumentation and a temporary flowmeter installed in accordance with the AFPC procedure were properly installed, calibrated and properly functioning. The observed process parameter values were consistent with the lineup of the system. The inspector noted appropriate tagging and configuration of pumps, valves, and breakers. Valve position was determined using local position indication, stem position (for rising stem valves), and operator assistance during the loop swap. One exception was noted during the walkdown. One valve was to be locked open per the lineup, however the plastic tie which is sometimes used in lieu of a padlock to draw plant personnel's attention to a valve's locked status had come away from the valve and was hanging attached to the chain on the valve. The inspector brought this to operations shift supervision's attention. The tie was replaced with a full chain and padlock during the loop swap described later in this section. (The decision to use a padlock had been made prior to the inspector's identification of the discrepancy.) The inspector did observe that although the control to lock the valve open was not intact, the valve was actually in the open position and was left securely locked following the RHR loop swap later that day.

Material conditions in the fuel pool cooling heat exchanger and residual heat removal areas were acceptable. The areas were free of extraneous rags, tape, etc. and were appropriately roped off for radiological conditions. Valves in the system exhibited acceptable if any packing leakage, had their handwheels intact, and were properly labeled. No prohibited ignition sources of flammable materials were present in the vicinity of the systems. Electrical cords for instrumentation installed temporarily for this mode of operation were secure and did not degrade system performance. The material condition of breaker cubicles were generally poor with dust and some extraneous material inside. This condition, although not ideal, was considered acceptable since it did not affect the operation of the equipment and the plant was in the middle of a refueling outage.

During this inspection, plant personnel conducted an RHR loop swap from the "B" loop to the "A" loop. Portions of this evolution were observed by the inspector to verify that the operation of the AFPC system was conducted in a controlled and appropriate manner. The inspector observed a thorough pre-evolution brief in the control room. The evolution was carefully planned and controlled by operations personnel. Several operators were dedicated to the swap and were designated to appropriate areas in accordance with their exposure record. Communication between the evolution controller and operators and the control room was good. The swap from one loop of AFPC to the other was conducted in accordance with the operating procedure and the tagging changes were well controlled. Proper system lineup was observed following the RHR loop swap.

Overall, the inspector noted acceptable AFPC configuration, material condition, and operation. Drawings matched operating procedures, components were in their appropriate positions, material conditions were commensurate with the plant's shutdown mode, and changes to the system configuration were well executed.

3.0 MAINTENANCE AND SURVEILLANCE (61726, 62703, 62700)

3.1 Maintenance Repair Activities

The inspector reviewed the maintenance planning, work control, and conduct of repair activities for the following nine activities:

(1) MR #19403836, I&C installed new scram pilot valves on the reactor building west side HCU bank. Various stages of installation were observed on four assemblies as directed by procedure MR 1.5.3.

(2) Mechanical maintenance installed four replacement HCU scram valve diaphragms using several different MRs.

(3) MR #P9500248, mechanical maintenance (contractors) performed disassembly of HPCI check valve 23010-39.

(4) MR #19500453, I&C leak tested a new test valve installed at gage PSID 5040 B per modification FRN 95-04-09.

(5) MR #19080413, mechanical maintenance (BECO and contractors) performed machining and recorded fit-up measurements to support rebuild of MSIV (AO-203-2A) per FRN 95-03-75. The inspector noted a very detailed work package was developed to perform this work.

(6) MR #P9404237, mechanical maintenance removed air-operated secondary containment isolation dampers AON 116 & 117 to support required PMs.

(7) MR #19401876, contractors installed a section of 1" chrome-moly piping in the RCIC drain line.

(8) MR #19403616, mechanical maintenance (contractors) replaced two RCIC 1" drain line valves HO-1301-105 & 106.

(9) MR #19402481, contractors performed PM & MOV design change on RCIC pump torus suction MO-1301-26. The inspector noted that a hold point had been added to the MR to have the system engineer specify the correct serial number for the replacement motor to ensure the replacement motor had the required torque characteristics. This oversight in the original MR (identified by the assigned contractor job site supervisor) could have resulted in a rework item similar to a previous rework problem identified recently. This was confirmed by site management during the informal exit meeting briefing.

In general, the inspector concluded that maintenance activities were well conducted. The HCU scram pilot valve replacement work was well planned and executed by I&C and resulted in a substantial savings in radiation exposure to the workers. Replacement assemblies were built and pre-tested in the shop minimizing the work required for installation in the plant. During installation I&C used heat shrinkable material to insulate the electrical connections which resulted in a more efficient installation and further reduced radiation exposure. In addition, mechanical maintenance was tasked with parallel replacement of the HCU scram valve diaphragms. Mechanical maintenance and I&C coordinated their parallel work on the HCUs well.

The inspector had the following general observations for the nine activities witnessed. Good pre-job briefs were observed. Mechanics were knowledgeable of the assigned tasks. Work activities were well coordinated with operations. HP coverage was present, providing the workers direction. Supervisory oversight was judged to be adequate to very good, but varied from job to job. Work packages were appropriately detailed and in fact the modification packages reviewed contained a lot of background information that may not be necessary for the performance of the work.

An area of potential weakness was identified in that workers failed to sign off steps in the procedures as the work was performed in four of the nine activities observed (MR #19401876, 19403616, 19500453, P9404237). In all four cases the procedures were signed off later in the office and no occurrences of failure to follow procedures were observed. However, this is an area of potential weakness and could lead to more serious problems if permitted. For example, MR #19403616, replaced two RCIC 1" drain line valves HO-1301-105 & 106. Weld joint fit-ups/tacks/final welds & visual inspections for the field welds were not signed off at the time work was completed by the welders, but were signed off by the foreman after the fact in the office. The inspector questioned the acceptability of this practice of having a foreman who was not physically present at the job site at the time the work was performed verify proper completion. Additionally, the inspector observed I&C technicians use out-of-date prints during a safety-related post work testing activity on the "A" EDG. Although this did not represent a violation since the prints were basically used to locate components, the inspector considered the use of out-of-date prints to be a poor practice. Maintenance management initiated a problem report and held a critique to address this issue. The inspector brought these concerns to the attention of senior plant management. Senior plant management agreed with the inspector's concern that the person performing the work should be responsible for verifying proper completion of his work.

The inspector noted that quality assurance had issued a Level I deficiency report (#2064) in January 1995 for a repeat finding of failure to fully document completion of work in performing seven I&C surveillance procedures. Although, the quality assurance finding documented deficiencies in completed work packages and the inspector was reviewing work packages in progress the potential exists for repeating this problem of not completing work packages as required when steps in procedures are not signed off as the work is completed.

During the replacement of the control rod drive system common minimum flow isolation valve, the inspector noted that the replacement valve developed a body to bonnet leak. A freeze seal was used to re-establish the mechanical isolation, the replacement valve was cut out, and another new valve was installed. The work area was contaminated and was located in a radiation area. The inspector identified that no shop leak test was performed to verify the acceptability of the replacement valve, which had to be cut out of the system. The inspector considered that the lack of a shop leak test contributed to the need for this maintenance rework.

3.2 Routine Surveillances

The inspector observed portions of selected surveillances to verify proper calibration of test instrumentation, use of approved procedures, performance of work by qualified personnel, conformance to limiting conditions for operations, and correct system restoration following testing. The inspector noted two instances in which the operability of the electrical power components, and therefore the supported systems, were maintained; but this could only be confirmed by an "after-the-fact" review of operability determinations.

On April 26, 1995, a load shed relay operational/functional test was conducted to demonstrate the operability of the "A" train 4.16 KV emergency bus (A5). This test, conducted in accordance with PNPS procedure no. 3.M.3-47, is performed with no loads on bus A5 and with the "A" emergency diesel generator (EDG) inoperable. Successful conduct of this cold shutdown surveillance test was tracked as a limiting condition for operation (LCO) in the control room under log number T95-109. After completion of the load shed logic test and planned A5 bus preventive maintenance, also tracked on LCO T95-109, the "A" train 4.16 KV emergency bus was declared operable on April 27, 1995.

With the restoration of the A5 bus capable of providing power to the "A" train core spray (CS) system, the licensee removed the "B" train CS system from service on April 27, 1995, essentially conducting a "protected loop swap." The "B" loop equipment had been heretofore considered available and administratively protected from outage work while the "A" loop was out of service. On April 27, 1995, the licensee altered its "protected loop" configuration with the "A" loop restored and the "B" loop removed from service. At the same time, the "A" EDG was considered available, but not yet operable because an emergency backup, dc powered fuel oil pump had failed and had been electrically isolated for troubleshooting and repair.

Since control rod drive (i.e., CRD 06-39) replacement was in progress overnight on April 27-28, 1995, the inspector questioned whether the licensee met the intent of the PNPS Technical Specification (TS) 3.5.F.3 by performing work that had "the potential for draining the reactor vessel" (i.e., the CRD replacement) with an inoperable EDG supporting the "A" core spray system. On April 28, 1995, the licensee issued an engineering evaluation that determined that the "A" EDG remained operable with the dc powered fuel oil pump disabled. This conclusion was based upon the fact that this fuel oil pump is a backup pump, which provides a redundant function, and is not required either for starting the EDG or for peaking power requirements. The inspector reviewed the engineering evaluation, performed in accordance with an engineering department instruction (NEDWI 395), and also reviewed the problem report (PR 95.9224) initially documenting the concern with the backup fuel oil pump. The inspector verified that the engineering evaluation was consistent with a previous safety evaluation (SE 2564) performed in conjunction with a modification to the EDG fuel booster pump design (reference: plant design change, PDC 88-19). The licensee's current engineering evaluation, confirming that an operable EDG was available to support the CS system, also demonstrated compliance with TS 3.5.F.3 during the period of time CRD 06-39 replacement was ongoing as an activity with the potential of draining the reactor vessel.

While no TS violation was identified during the protected loop swap on April 27, 1995, the licensee's judgment in removing the "B" CS system from service until the "A" EDG was declared operable to support the "A" CS system operability was suspect. The inspector discussed this issue with operations section management and licensing division personnel. As a result, the licensee issued a PNPS Technical Specification Clarification for section 3.5.F, which concludes that an operable EDG is required to support core cooling makeup water systems under the conditions prescribed by TS 3.5.F.3.

In the second instance on April 29, 1995, after the "A" EDG operability had been established by an engineering evaluation, the licensee discovered that a required degraded voltage surveillance test, satisfying TS Table 3.2B for the "A" train 4.16KV emergency bus, had not been performed prior to the A5 bus being declared operable. A licensee investigation revealed that the need for such testing had not been administratively transferred to the LCO (T95-109) tracking the operability requirements of A5 during the bus outage. Since the missed surveillance was a monthly test that could not be performed with the bus out of service, it should have been performed upon re-energization of the bus prior to declaring A5 operable. A problem report, PR 95.9250, was issued to document the specific missed surveillance and related programmatic concerns.

Because another procedural test of the undervoltage auxiliary contacts associated with the A5 outage had been completed prior to declaring the bus operable, TS Table 3.2B surveillance requirements had been met and the bus A5 operability was not in question. Additionally, the missed surveillance was successfully performed after discovery of the problem on April 29, 1995. On May 1, 1995, the inspector witnessed the licensee critique meeting held to discuss the facts associated with this issue. Although bus A5 operability had been actually maintained at the time required to support "A" loop system (e.g., CS) operation, the programmatic failure of the Master Surveillance Tracking Program (MSTP) to control the conduct of a required surveillance remained a concern. As a result, the licensee directed that MSTP procedure 1.8 be revised to provide guidance for the proper dispositioning of surveillance test requirements. Additionally, the MSTP was further reviewed for any other surveillances with an expired or soon to be expired grace period. No other problems were identified by the licensee.

The inspector reviewed PR 95.9250 and the Office Memorandum (MSM 95-46) documenting the critique and root cause analysis response for the missed surveillance. The root and contributing causes to this concern were assessed, the extent of the problem was bounded, and corrective actions were directed and taken. The inspector noted that accountability for ensuring that specific surveillance tasks are included in the appropriate system LCO's was directed toward the repetitive task coordinators, who are assigned responsibility for the update of the affected LCO's in the control room. In this case, a personnel error in coordination caused the surveillance to be missed, but the licensee is appropriately enhancing the program guidance with an MSTP procedure revision.

The inspector has no further questions regarding either the bus A5 or "A" EDG operability issues discussed above. In both cases the operability of the electrical power components, and therefore the supported systems, was maintained; but this could only be confirmed by an "after-the-fact" review of operability determinations. The inspector reviewed the licensee evaluations and planned and/or completed corrective actions. While errors did occur, creating the operability concerns, no TS violations were identified. The licensee response to these issues appears comprehensive and appropriately directed to prevent problem recurrence. The inspector has no additional questions regarding the system operability and surveillance testing concerns raised during this inspection.

3.3 Planning For Refueling Outage 10

The inspector attended several daily refueling outage meetings and noted a need for improved outage planning. The inspector noted that there were a number of parts identified as unavailable to support the scheduled work. The licensee indicated that there were approximately two hundred maintenance activities that were affected by unavailability of parts at the beginning of the outage. The licensee also indicated that the extended mid-cycle outage completed recently had significantly impacted the planning efforts for the current outage.

The inspector also noted that the meetings revealed that the schedule was in several cases either incomplete or in error which led to confusion regarding the work scope. Although the inspector did not identify any work control problems or work errors linked to poor planning, the inspector was concerned that weak planning efforts could lead to problems in the field or unnecessary challenges to the work control process. The inspector was informed by the plant manager that BECO had visited other utilities and were evaluating various improvements in the areas of planning and scheduling which included centralizing outage and work week management into one group.

3.4 Maintenance Request Backlog

The inspector reviewed the current backlog for seven safety systems and concluded that many of the items were newly added during the current outage as a way tracking outstanding items such as post maintenance testing and the older items were either scheduled to work during the outage or did not appear to affect system operability. The inspector concluded that the maintenance backlog was being appropriately managed for the systems reviewed. The inspector was informed by the maintenance section manager that efforts were being planned to systematically reduce the maintenance backlog in the future.

3.5 Maintenance Improvement Initiatives

The inspector reviewed the actions recently taken by BECO to perform maintenance program performance assessments and concluded although a new and greatly expanded program has been developed, it was too early to assess the effectiveness of this initiative. The inspector reviewed a sample of recently completed assessments of maintenance and surveillance activities and concluded that the assessments did not appear to provide much feedback on qualitative performance. BECO recently issued a new procedure on April 11, 1995 that established a new and greatly expanded program for conducting maintenance performance assessments (procedure no. 1.5.18).

The inspector also reviewed the actions recently taken by BECO to revamp the existing performance indicators used by the maintenance section. The inspector reviewed a sample of the performance indicators issued in the past six months and noted the performance indicators for the maintenance section did not have established performance standards against which actual performance was evaluated and trended (e.g. a goal of completing 80% of the jobs planned on time). In addition, the inspector noted the most recently issued maintenance performance indicators did not include overdue preventative maintenance and surveillance tasks. The maintenance section manager indicated that he recently revised the performance indicators to include performance standards against which actual performance could be evaluated and trended. The licensee reported that performance indicators for preventive maintenance and surveillance tasks would be kept in the future.

4.0 ENGINEERING (37551, 40500, 92903)

4.1 Augmented Examination of Reactor Vessel

10 CFR 50.55a(g)(6)(ii)(A), Augmented Examination of Reactor Vessel, requires licensees to implement a one time examination of "essentially 100%" of the reactor pressure vessel shell welds as specified in Item B1.10, Examination Category B-A, "Pressure Retaining Welds in Reactor Vessel," in Table IWB-2500-1 of the 1989 Edition of the American Society of Mechanical Engineers (ASME) Section XI. 10 CFR 50.55a(g)(6)(ii)(A)(2) defines "essentially 100%" examination as more than 90% of the examination volume of each weld. The schedule for implementation of the augmented inspection is dependent upon the number of months remaining in the 10-year inservice inspection (ISI) interval that was in effect on September 8, 1992. Depending on the type of reactor (PWR or BWR), vintage, and available inside or outside vessel surface access, meeting the requirements of the rule can involve varying degrees of difficulty. In general, BWRs have more limited access to Item B1.10 reactor pressure vessel (RPV) welds than the PWRs, and thus will have greater difficulty meeting the coverage requirements of the rule.

4.1.1 Analysis Reports

In preparation for the augmented reactor vessel examination and other vessel integrity concerns, BECo commissioned several reports to look at reactor vessel stresses, fatigue life, and flaw tolerance. The inspector reviewed portions of the Altran technical report 93177-TR-01, "Pilgrim Reactor Vessel Cyclic Load Analysis," dated July 1994, and Altran technical report 93177-TR-04, Rev. 0, "Evaluation of Reactor Pressure Vessel Materials Properties for Pilgrim," dated August 1994. The inspector reviewed the reports and discussed them with BECo Engineering personnel. These reports contain updated fatigue and fracture mechanics analyses more exact than the original design calculations. The report vendors removed broad, conservative assumptions for these calculations and replaced certain assumed values with data from actual operating experience. No discrepancies were identified.

4.1.2 Access Studies

The licensee contracted with two different vendors to conduct access studies of the inside of the reactor vessel during refueling outage (RFO) 8 in 1991 and RFO 9 in 1993 before the actual examination was to be done in the current outage, RFO 10. The first study used a go/no go gage to check clearances while the second made actual measurements of clearances along the inside surface of the RPV. Results from the access studies were used for planning and estimation of weld coverage. Weld coverage was estimated at 83% using automated ultrasonic equipment from inside the RPV. BECo planned to augment the internal examination with manual examinations of welds near nozzle blockouts from outside the RPV.

4.1.3 Digitization of Vessel Radiographs

The original construction radiographs of the BECo reactor vessel were required in accordance with the then-current requirements of the ASME Construction Code, Section III, 1965 Edition through January 1966 Addenda. These radiographs were taken and evaluated over two decades ago. Numerous indications, including small porosity and slag inclusions, were noted on the original radiograph reader sheets, evaluated, and found acceptable to the Construction Code criteria in effect when the Pilgrim station was licensed.

BECo has digitized the original vessel radiographs to be better able to evaluate any indications found during the augmented RPV examination. The resolution capability of the digital system was greater than the unaided eye when electronic image processing software was used. For example, an indication originally thought to be one large slag inclusion (up to approximately 3/4 inch), was determined, through digitization, to be composed of two smaller inclusions separated by base metal. The inspector observed general operation of the radiograph digitization equipment. The inspector also viewed the digitized image of the indication originally characterized as a 3/4 inch slag inclusion. Using the image enhancement capabilities of the digital system, the large indication actually appeared to the inspector to be two smaller indications, as the licensee had stated.

4.1.4 Examination

The examination during the April 1995 refueling outage at BECo was conducted with the GERIS-2000 system, an automated, remote ultrasonic scanning system. The GERIS tooling mast was mounted on an indexed ring which rested on top of the core shroud. Since the reactor vessel was not defueled at BECo, Operations personnel coordinated fuel movement with the GERIS inspection personnel to guard against interference of the inspection tool with fuel bundles. Ultrasonic scanning was accomplished with 14 transducers (arranged in various orientations so as to detect and size flaws from different directions) as described in the following table:

Number of Transducers	Type	Examination Purpose
4	45° Shear	Volume of metal
4	60° Shear	Volume of metal
4	70° Refracted Longitudinal	Underclad cracking
2	0° Straight Beam	Laminations and vessel thickness

Data was taken simultaneously for all 14 transducers so that an analyst could compare responses to indications for multiple orientations (up, down, clockwise and counter-clockwise) of the same type of transducer and for responses to different types of transducers. Video cameras were mounted on the inspection unit to observe the physical position of the unit and any obstructions in the vessel such as jet pumps. Scanning "patches" were done on lengths up to approximately 5 or 6 feet, with all data recorded on one optical disk. After data acquisition was completed for one patch, the original disk was copied to insure against data loss.

The inspector observed inspection personnel remotely conducting the examination from a location outside containment. The operators viewed the position of the UT scanning head with the video cameras mounted on the device. The inspector noted that the inspection personnel were in close contact with the responsible qualified UT Level III and BECo operations personnel, who were moving fuel while vessel inspections were conducted. A small technical problem in data transmission occurred while the inspector was present. The inspection personnel took the necessary steps to correct the problem and restart data acquisition.

The inspector reviewed BECo Temporary Procedure (TP) No. TP95-051, Rev. 0, "Procedure for the Examination of Reactor Pressure Vessel Welds with GERIS 2000 ID," dated March 17, 1995, and BECo TP95-052, Rev. 0, "Procedure for Reactor Pressure Vessel Flaw Sizing with the GERIS 2000 ID," dated March 17, 1995. The inspector requested qualification data on the UT methods documented in the procedures. Documented data was not available, because the methods had been demonstrated through the performance demonstration initiative (PDI) at Electric Power Research Institute (EPRI), and EPRI would not release qualification information to the UT vendor until 1996. The inspector reviewed a letter dated March 21, 1995, from BECo to the Chairman of PDI, which requested the performance demonstration data. The letter stated that access to the PDI flaw detection performance data would help evaluate alternative coverage approaches such as single sided access and examination with fewer beam angles. In addition, the letter requested statistical results to enable accurate sizing and evaluation of flaws. BECo stated that the response to the letter was negative.

Through review of the above mentioned procedures, and discussions with cognizant personnel, the inspector determined that single sided access examinations and examination with fewer beam angles were being utilized for weld coverage calculations. This item is to be addressed in BECo's submittal to the NRC, which is to be sent no later than 90 days after the refueling outage.

BECo indicated that only a few flaws were identified and were suspected to be slag or porosity. None of the flaws approached the ASME Code limits which would have required additional evaluations. Therefore, the statistical results for sizing and evaluation of flaws were not as pertinent. No indications were seen that had characteristics of intergranular stress corrosion cracking (IGSCC).

4.1.5 Evaluation

The inspector witnessed vendor Level III UT examiners evaluate data, and reviewed the analyst's method of data analysis. The examiners had a very good understanding of the equipment, ultrasonic techniques and capabilities, and evaluation of signals.

When the automated examinations were complete, BECo indicated that approximately 71% total coverage was obtained, which was less than the anticipated 83%. This calculated coverage did not include the reactor vessel to bottom head weld which was also an ASME Item B1.10 weld. It was not included in the total because no automated UT was performed on the weld due to access limitations. The Code of Federal Regulations required "essentially 100%" coverage of <u>each</u> weld. The actual coverage for each weld ranged from 0% (shorter vertical weld) to 98.5%. Some manual UT examinations were going to be performed from the outside wall of the RPV on the welds near nozzle blockouts, but BECo indicated that the additional amount of coverage that would be obtained was limited. BECo will document the final coverage for each weld, and submit the results to the NRC for review. The inspector discussed the issue with an NRR representative who stated that in accordance with the CFR, Pilgrim's augmented reactor vessel examination was not required to be completed during the current refueling outage. Therefore, additional outages remained during which BECo could perform additional examinations if necessary.

Fourteen transducers were used for scanning each weld, but there were portions of some welds where all fourteen transducers could not be utilized due to access limitations. Procedure TP95-052 indicated that for purposes of calculating the "effective" weld coverage, the use of all fourteen transducers was not required. Only four transducers were required for effective coverage.

- One 70° Refracted longitudinal transducer parallel to the weld
- One 45° Shear wave transducer parallel to the weld
- One 70° Refracted longitudinal transducer perpendicular to the weld
- One 45° Shear wave transducer perpendicular to the weld

Therefore, single sided coverage with fewer transducers was being utilized to determine effective coverage. In addition, inspection by only two transducers (either parallel or perpendicular) was considered to be 50% coverage, as indicated in section 4.1.2 of this report

4.1.6 Conclusions

It was evident that considerable effort was spent preparing for the augmented RPV examination. This was seen in the pre-outage review of RPV stresses, fatigue life, and flaw tolerances, in the performance of two access studies, and the digitization of vessel radiographs in preparation for flaw evaluation. Personnel involved in conducting the examination and evaluating the data were very knowledgeable of the procedural requirements, UT equipment and techniques, and evaluation methods. Very few flaws were identified, and all were determined to be acceptable per ASME Code acceptance standards. The issue concerning completeness of the examination (i.e. total weld coverage) is to be addressed in future BECo communications with NRR.

4.2 Core Shroud Inspection and Modification

Throughout industry, boiling water reactors have identified IGSCC in core shroud welds. Prior to RFO 10, BECo decided to install a preemptive core shroud repair. To assure the integrity of the repair, BECo committed to performing an enhanced level 1 visual (EVT1) inspection of certain portions of the core shroud. The inspector reviewed activities associated with the EVT1 of the core shroud, and core shroud repair installation.

4.2.1 Inspection of Core Shroud

EVT1 examinations were performed on several vertical core shroud welds, and on the four gusset welds affected by the core shroud repair. The inspector reviewed videotapes of several of the completed examinations and determined that the quality of the data looked good. The inspector verified that the examinations had been performed and analyzed by qualified personnel. The locations inspected were in accordance with BECo's commitments to the NRC. At the time of the inspection, the visual examination data sheets had not been completed. Following the inspection, the data sheets were forwarded to the inspector for in-office review. The inspector determined that they were consistent with what had been verbalized during the inspection.

No indications were seen on the gusset welds or on any of the vertical welds. One crack was identified on the horizontal, H4, weld while the visual inspection was being performed on a vertical weld. The visible portion of the crack was estimated to be four feet long. The crack continued into portions of the weld that had not been brushed clean, and the crack was no longer visible. Therefore the crack may have been longer than four feet. This indication was bounded by the core shroud repair modification, because the repair was designed to compensate for the structural integrity of all circumferential welds. Per the design requirements, each circumferential weld could be assumed to have a 360° through-wall crack, and the repair would compensate accordingly.

The visual inspection data was reviewed by both a vendor qualified level III analyst, and a BECo quality control engineer. The review consisted of data evaluation, determination of adequate coverage, and assurance of quality of examinations. The inspector reviewed the quality control inspection reports and noted that substantial observations had been made. As a result, BECo required several visual inspection retakes to obtain additional coverage in the area of interest, and to improve the quality of the examination.

4.2.2 Core Shroud Repair Activities

The core shroud repair was designed and installed by a vendor. The vendor worked under their quality assurance program and provided quality assurance personnel support to the project. BECo provided quality assurance oversight to the repair project. As a result, any deviations or nonconformances identified by the vendor were initially documented utilizing vendor procedures (i.e. vendor nonconformance report [NCR], or deviation disposition request [DDR]). These reports were then reviewed and dispositioned by vendor personnel.

As an additional measure, BECo made each of those reports into a BECo NCR. The BECo NCR required the BECo engineering department to review and concur on each issue that was raised. The BECo NCR could not be closed out until documentation was obtained that proved that the vendor NCR or DDR recommended disposition was completed. The inspector determined that this process provided an independent review of each nonconformance/deviation and provided BECo with a means of tracking deficiencies to completion.

The inspector reviewed fifteen BECo NCRs that were initiated due to deviations identified at the manufacturing plant and during on-site receipt inspections. Good, solid technical justifications for deviation resolutions were provided. In addition, closeout documentation was available for all NCRs that were considered complete.

BECo's contractor identified an indication of a potential defect within the weld area of the zero degree azimuth core shroud support ring (also known as the jet pump diffuser plate) access hole cover during an enhanced VT-1 per ASME Boiler Pressure Vessel Code Section XI, visual inspection of the reactor internals on May 8, 1995. The weld was examined by ultrasonic examination; there was no evidence of circumferential or radial cracking.

The inspector reviewed the video tape of the enhanced VT-1 inspection with licensee personnel. The in-vessel examination had been qualified with a 0.0005 inch diameter wire. The images were of high quality and the 0.0005 inch diameter wire was clearly visible. The visual indication of interest was circumferential and about eighteen inches in length. It was unusual in that it appeared to be located in the approximate center of the circumferential weld and also had a very jagged profile; irregular sharply changing direction in a saw tooth manner.

The inspector also reviewed the ultrasonic test examination report, GE Project No. 1FX4V. The examination found that during the automated ultrasonic examination no indications associated with intergranular stress corrosion cracking were recorded by the GE Smart 2000 system utilizing 45° sheer wave and 60° refracted longitudinal wave search units; the inside diameter geometry was recorded with both 45° sheer and 60° refracted longitudinal units. However, because of the proximity of the reactor vessel and the shroud wall, approximately 45% of the weld circumference was not examined from the ledge or support ring side. The inspector discussed this with BECo personnel and concluded that the examination would have detected cracking if present in the visual indication that ran from approximately 8:00 to 1:00 (with 12:00 positioned at the vessel wall) around the circumferential weld.

Intergranular stress corrosion cracking has been discovered at some boiling water reactors. It has generally been circumferential following a crevice below the weld location. However, there have been some incidents of radial cracking into the support plate. The issue is discussed in General Electric Service Information Letter (SIL) No. 462 and its supplements and revision.

The Pilgrim Station reactor shroud support ring is approximately two inch thick Alloy 600 material. The access hole cover is approximately one inch thick Alloy 600 material and 19.91 inches in diameter; it was fabricated with a 0.5 inch radius weld preparation profile in its upper edge, the radius cut was positioned to leave a 0.06 inch land at the lower edge. The circumferential crevice is located along this land and has been the site from which cracking has been detected to originate at other reactor facilities. The crack normally traveled upward along the weld vertical fusion line.

BECo has previously inspected this weld by ultrasonic examination in 1991 and in a visual VT-1 examination in 1993. There were no defects reported from those inspections. Because the cracking originates from the vertical crevice at the bottom of the plate, General Electric has recommended in their June 8, 1992, Supplement 3 to SIL No. 462, that both visual, ASME Section XI VT-1, and ultrasonic inspections be made using the best available techniques for both circumferential and radial crack detection. The inspector observed that BECo had acted in a conservative manner to categorize the visual indication of this potential flaw.

Core shroud repair components were receipt inspected on-site by vendor personnel. Depending on the component received, the level of review varied. Several components required last minute machining at the manufacturing plant based on actual core shroud configuration measurements obtained by vendor personnel. The inspector determined that there was no formal process utilized to communicate the special dimensions from on-site personnel to the manufacturing plant. The final component dimensions were measured at the manufacturing plant and documented on paperwork which was shipped to site with the component. Through observation and review of documentation, the inspector verified that the receipt inspector verified the documented dimensions against the vendor's work travelers. The travelers were originally used to obtain the specific dimensions. Although a formal process was not being utilized to convey special dimensions from the site to the manufacturing plant, BECo was taking adequate actions to assure accurate information was forwarded.

The inspector noted good BECo quality assurance oversight of the vendor's quality assurance department personnel. This was identified in the review of source inspection reports and contractor surveillance monitoring reports.

4.2.3 Conclusions

EVT1 examinations were performed by qualified personnel, in accordance with the procedure and commitments made to the NRC. No relevant indications were identified in the vertical or gusset welds. Through the visual inspection review process, substantial observations were made which increased the effectiveness and quality of the EVT1 examinations. Nonconformance reports initiated during the core shroud repair project contained good technical justifications for proposed resolution. The inspector identified a strength in that BECo maintained control of the NCR process. Receipt inspections were performed in accordance with the level of review necessary for individual components. Good BECo quality assurance oversight of the vendor's quality assurance department personnel was identified.

4.3 (Open) Unresolved Item (50-293/95-09-01): Repair of Emergency Diesel Generator (EDG) A

Boston Edison Company (BECo) removed the 'A' EDG from service during the refueling outage to investigate an abnormal sound heard from the generator while the engine was running. That inspection was made with the aid of a fiberscope and revealed loose (magnetic core) laminations of the generator stator. In response to that finding, the generator stator and rotor were removed and shipped to a repair facility to be refurbished. Related to this problem, the inspector reviewed the associated Problem Report, No. 95.9176. Work Request Tag, No. 020261, and Maintenance Request, No. 19201976.

After operators detected a "buzzing sound on June 29, 1992, from the "A" EDG the first actions taken to troubleshoot the generator were when a manufacturer's representative observed both diesels running during his August 10 through 12, 1992 site visit. The inspector reviewed the NEI Peebles, Electric Products, Inc. Service Report No. F-1130. The representative concluded that the sound appeared to be magnetic and indicative of possible loose laminations. He recommended that the unit be disassembled, cleaned, inspected and dipped if necessary. The representative concurred with BECo's desire to wait until the April 1993 refueling outage to perform this inspection as long as the sound was monitored each time the unit was run. He cautioned that if the sound increased in level or appeared to occur in additional areas, it may be necessary to perform the disassembly sooner. However, these recommendations were based on the assumption that the engine was run once a month for only a few hours; there was no analysis of its ability to successfully operate for the duration under the conditions specified in the facility safety analysis report (7 days).

BECo also received a proposal from Westinghouse Electric Corporation for diagnostic testing that included acoustic tests, fiberscope visual examination and electromagnetic testing on October 16, 1992. The noise and vibration tests were performed on February 15 and 16, 1995 and the fiberscope examination was conducted during the refueling outage in early April 1995. Based on the findings during the visual examination, the electromagnetic tests of the stator core were not completed.

The inspector reviewed the report on the noise and vibration tests made by Westinghouse. The report concluded the vibration signatures indicate that they are electrical in origin, that higher frequency harmonics and side-bands are noticeable on the 'A' EDG; that they are highest over the second row of laminations and may be an indication of loose laminations or radial vent plates. The report recommended further visual and eddy-current inspection. The report suggested that structural looseness in the core will progress until high cycle fatigue causes a metal part to fail. The loose piece of metal would remain in the machine held in place by the magnetic field. It would continue to rub, possibly against insulation leading to a more catastrophic electrical failure.

The machine was taken out of service disassembled and shipped to a repair facility to be refurbished. The repair included removal of broken and loose lamination pieces from the stator; cleaning and drying the stator and rotor; and, vacuum pressure impregnation of the stator with resin. The inspector was briefed on corrective actions for other minor nonconforming items as repair of the internal electric heater. BECo made a fiberscope examination of the 'B' EDG on May 4, 1995; there were no deficiencies identified.

The inspector reviewed the performance history for both of the generators including a licensee event report, LER 78-049, that reported a failure of the 'B' EDG on October 11, 1978 during a monthly surveillance test. That event concerned a generator stator winding fault that tripped the unit output breaker after approximately sixteen minutes of operation at rated load. The stated cause was a short circuit from a coil to the stator caused by loose laminations. Although there was no other written documentation concerning this event, BECo staff personnel offered information that the failure was believed to have been related to an out-of-phase closure of the generator output breaker.

The inspector did not locate any additional information on inspections of the 'A' EDG related to the failure of the 'B' EDG generator. Although the deficiency was carried on system status reports following the manufacturer's representative visit, the information addressed budget requests for inspection and repair; but, did not address the long term operability of the machine. Although requested funding was not approved in 1992 and 1993, there was no record for this reasoning. Although the senior BECo managers to which the requests were directed are no longer with the company, plant personnel related their opinion to the inspector that the noise was not significant as related to equipment operability.

Following this review the inspector concluded that although the initial discovery of the abnormal sound was a very good and perceptive observation on the part of the operator, BECo did not aggressively pursue the long term effect on equipment operability. Although the manufacture's representative suspected loose stator core laminations during his site visit one month after the initial observation was recorded on June 29, 1992, there was no visual (fiberscope) inspection made until April 1995. There was no long term operability consideration given to the loss of structural integrity and vibrating laminations in the stator core. Potential failure mechanisms such as high cycle fatigue and subsequent damage to stator winding insulation or to the potential for localized hot spots due to eddy currents did not appear to be considered.

This area is an unresolved item pending NRC staff review of the after-the-fact operability determination completed during the recent outage. **(UNR 50-293/95-09-01)**

4.4 Hydrodynamic Diagnostic Testing of RCIC Injection Valve

The licensee diagnostically tested the RCIC pump discharge injection valve No. 2 (1301-49) in accordance with procedures 8.7.1.18, "MOV Hydrodynamic Differential Pressure Test Procedure For GL 89-10," Revision 3, dated February 28, 1995, and 3.M.3-24.12, "VOTES 100 Operating Procedure," Revision 4, dated March 24, 1995. The procedure contained appropriate acceptance criteria for the data collected. After each valve stroke the data was collected by qualified, knowledgeable personnel and recorded and compared to the acceptance criteria. The motor operated valve (MOV) test engineer coordinated the activities of the VOTES technicians, electrical personnel, hydrodynamic pump operators, and the control room to perform a well-controlled test.

The licensee performs at least three strokes during the testing to get a good sample of the measured parameters and to detect any trends. The inspector considered this a proactive practice which should provide meaningful trending data. If a trend is noted, more test strokes are performed for later evaluation. During this test, all values of torque and thrust were within their acceptable limits. The inspector observed good communications and proper resolution of discrepancies found during the hydrostatic test. Current test procedures were used and well understood by qualified test personnel. Acceptance criteria were appropriate and the testing method (i.e. repeated valve stroking) was considered a strength.

Additionally, the inspector reviewed the overall status of static and dynamic motor operated valve testing pursuant to NRC Generic Letter 89-10 and also consideration for pressure locking. All phase I valves, required to change position in an accident condition, have been evaluated by BECo as either not susceptible to pressure locking, or have been modified. The dynamic testing of all phase I valves has been completed. The completion of all phase II valves is scheduled to be completed at the end of the next refueling outage, RFO11. Significant progress of safety-related motor operated valves was made during RFO10 including: 63 inspections, 15 overhauls, 40 static tests, and 35 dynamic tests. BECo performed well by making substantial progress in addressing the issues of NRC Generic Letter 89-10. Synergies were formed between engineering, maintenance and operations to complete the work.

4.5 (Open) Unresolved Item (50-293/95-09-02): Recirculation Pump Speed Control Digital Upgrade

4.5.1 Background

The recirculation pump speed control Plant Design Change (PDC) No. 95-35 was inspected on May 8-12, 1995. The modification was at the checkout phase prior to preoperational testing at the time of the inspection.

This PDC was the second which addresses uncontrolled recirculation pump excursions traceable to component aging within the M-G set speed control system. The first, PDC No. 94-09, added manual scoop tube positioner lockup switches on the main control panel to allow plant operators to stop unacceptable system performance.

The modification replaces the analog recirculation pump speed controllers for both loops with digital controllers. The master control feature was removed. The automatic control mode for each loop was restored, which allows operator setpoint closed loop control of pump speed. The automatic mode was used from 1972 to 1990. The manual open loop control mode was not changed.

The digital equipment involved in this modification is the Foxboro SPEC 200 MICRO microprocessor-based product that the NRC has previously reviewed for safety-related applications at the other nuclear power plants.

The input/output (I/O) for the modification involved one analog voltage input, three digital contact inputs, two analog current outputs and four digital contact outputs. The digital processing for each loop involved two Foxboro control processor cards, each programmed with the Foxboro maximum of six software control blocks. The overall processing time, from input to output, is approximately 0.4 second.

A new digital controller display was added to the control room benchboard for each loop, which from an operator viewpoint is different than the prior analog display. These differences are described in section 4.5.6 of this report on plant operator training.

Two operator-aid type system alarms were added to the prior design: 1) speed rate exceeds 3%/second, increasing or decreasing; 2) deviation between speed and speed demand greater than 3% for more than 5 seconds. These alarms provide the operator with more detailed information about system operation.

An alarm was added that indicates digital controller diagnostic errors. The digital system periodically checks itself for operational faults. Any of the following digital controller diagnostic errors are alarmed on one annunciator window in the control room: display station-to-controller data link halted; memory backup battery voltage low; random-access memory (RAM) parity error or no data base; read-only memory (ROM) checksum error; failed calibration coefficients in programmable read-only memory (PROM); readback failure on output write; and, "watchdog" time-out or processing overrun.

The two recirculation pump speed limiter protection features were retained. Speed limiter No. 1 automatically limits the recirculation pump speed to 26 percent of rated speed if the recirculation pump main discharge valve is not fully open or the total feedwater flow is less than 20 percent of rated flow. Without this speed limiter, the recirculation pump could overheat if the recirculation pump discharge valve is partly closed. This speed limiter also prevents cavitation in the recirculation or jet pumps if the feedwater flow drops below 20 percent of rated flow.

Speed limiter No. 2 automatically limits the recirculation pump speed to 44 percent of rated speed if one of the three feedwater pumps is tripped off coincident with the reactor water level below the low level alarm set point. This reduction of the recirculation pump speed reduces the reactor power to a level within the capacity of the remaining feedwater flow, thus making a low water level scram unnecessary.

4.5.2 Scope and Method of Review

The purpose of this inspection was to assess the safety and engineering aspects of the recirculation pump speed control analog-to-digital upgrade modification. The quality of the digital and software design process was emphasized, since these were areas new to the licensee.

The inspectors reviewed the system based on NRC inspection manual guidance concerning design changes and modifications (37700). EPRI Report TR-102348, "Guideline on Licensing Digital Upgrades" was used as a reference, since the licensee referenced this report.

The digital segments were assessed for the quality of the following areas:

1. system bases and translation to digital requirements;
2. accuracy of analog-to-digital requirements translation;
3. digital sample data system analysis;
4. specification and design of digital equipment hardware and software;
5. hardware/software error management at the system and module level (to include microprocessor bus and data link);
6. software verification and validation (V&V);
7. electromagnetic susceptibility (EMI);
8. software documentation traceability and accuracy;
9. software configuration management and media control;
10. system acceptance and operational testing;
11. human machine interface;
12. engineer, operator, I&C, and maintenance training.

After the quality of the unique digital segments was determined, the entire modification was reviewed to determine the degree of conformance to NRC and licensee's requirements.

4.5.3 10 CFR 50.59 Safety Evaluation

The circuits affected by this modification are classified as non-safety related. The transient/accident analysis do credit coastdown of the MG sets and the consequent coastdown of the recirculation pumps; however, this modification does not affect the components required to effect coastdown, so the changes do not affect the results of the transient/accident analyses. The evaluation stated that the failure modes and effects of the modified system are identical to those that could occur with the existing control system and are analyzed in the FSAR. The evaluation went on to state that for all the failure modes, if the operators do not take appropriate actions, the totally independent safety-related reactor protection system is designed to automatically shut down the reactor if unsafe conditions are approached. The inspectors agreed that the reactor protection system is designed to actuate if unsafe conditions are approached, but did not agree that the failure modes and effects of the modified system are identical with the existing system.

The evaluation relied solely on the functional failures of the analog system and did not explicitly consider the new failures that are possible with the new implementation. Four bounding failures were considered, but the mapping of those failures to possible new failure modes was not made. The bounding failures may indeed be correct, but since the trace from any possible digital failures to the bounding effects is not clear, the conclusions are not clear.

Therefore, it was not evident that the failure modes listed in the safety evaluation included the failure modes unique to the recirculation pump speed control digital equipment. The licensee plans to address this by making a new safety evaluation in Problem Report (PR) No. 95.0369. This will remain as an unresolved item pending NRC review of the licensee's revised safety evaluation. **(UNR 50-293/95-09-02)**

4.5.4 Analog-to-Digital Requirements Translation

- **Design Requirements**

The inspectors reviewed the accuracy of the translation between the vendor purchase specification, which was the system design requirements written by the licensee, and the logic diagrams prepared by the vendor. The logic diagrams showed in symbolic notation the functional interconnection of the control blocks that were programmed in the software configuration data base.

The inspectors traced the system description as it will appear in the revised FSAR to the purchase specification. The inspectors noted that the specification contained more detail than the FSAR, since it was used by the vendor as the system requirements document. The FSAR general description agreed with the purchase specification, except in the matter of setpoints. This was resolved and is discussed below, and also in the software configuration management section. While verifying the vendor control logic drawings with the functional control drawings (FCD) that appear in the FSAR, the inspectors noted a functional misrepresentation of limiter No. 2 in the functional control drawing (FCD.) The inspectors noted that the FCD was used in operator training. The I&C engineer stated that Problem Report 95.0360 would start corrective action on the FCD. The revised FDC will then be used for operator training.

The vendor used the purchase specification to develop a separate system description based on the use of the software control blocks in the design. The inspectors traced the licensee's purchase specification to the vendor system design description and the logic diagrams. The inspectors noted one discrepancy: the vendor description included a priority scheme between speed limiter Nos. 1 and 2, which was not a requirement found in the purchase specification. The inspectors determined by interviews that the difference was created to resolve a problem discovered during a design review held before the factory acceptance test (FAT.) The licensee plans to resolve this difference in the revisions of the purchase specification to be made at the conclusion of the modification as documented in Problem Report No. 95.0360.

The inspectors observed that the digital controller purchase specification, the system description/factory acceptance test procedure, vendor logic drawings, and the software data base configuration document, in the aggregate, specified and described the functional software design. The inspectors were concerned that all of the separate design revisions would not be transferred to the original documents. Unless this was done, it would be difficult for someone to understand the digital controller software functions because important information would be fragmented. The principal I&C engineer stated that all the documents would be updated and corrected as part of the design change package closeout procedure. He documented this in problem report number 95.0360 to ensure follow-on actions. The inspectors considered this appropriate action to resolve the concern.

The inspectors verified that the system requirements correctly trace from the purchase specification to the logic diagram and software database document with the appropriate problem report corrective action.

- **Vendor Software V&V**

The Foxboro base software V&V was documented in Foxboro test report number QOAAE03, Revision B (October 26,1988) entitled "Spec 200 MICRO software Validation and Verification." This report compared the development procedures to those in ANSI/IEEE Standard 730-1984, "Standard for Software Quality Assurance Plans." The licensee read this report and accepted it as satisfactory evidence of software V&V for the recirculation pump speed control non-safety modification.

For this application, the inspectors concluded that the licensee appropriately considered the quality of the vendor base software V&V.

- **Electromagnetic Susceptibility (EMI)**

The licensee reviewed a test report for the conducted and radiated EMI susceptibility testing of a similar SPEC 200 MICRO installation at another nuclear plant. The results were compared to the type and levels of the tests in EPRI report TR-102323 "Guidelines for Electromagnetic Interference Testing in Power Plants," Appendix B, "EMI Susceptibility Guide." The licensee found that the continuous wave conducted/radiated and the surge tests were covered. The fast transient tests were not covered. While not a requirement, the design engineer did not measure or estimate the actual installed EMI environment and compare it with the vendor EMI test levels.

The control benchboard operator display is connected to the controller cards, located in the back row panels of the control room, by a serial communications cable. The cable from the controllers in the back row panels of the control room to the displays on the control bench board is a 30 conductor vendor fabricated cable with no overall shield that meets the flame test requirements of IEEE Standard 383-1974. The vendor stated that the cable has been tested as part of a connected system for surge EMI tests. The data rate is 3.5 kilobytes/sec, error checking is employed for the data messages, and the message protocol is based on a widely used listener/talker protocol, but is considered proprietary.

For this application, the inspectors concluded that the licensee appropriately considered the EMI effects by the review and analysis of testing on comparable vendor equipment used in a nuclear power plant.

- **Digital Design Process**

There was no definitive digital upgrade guidance documents or procedures for engineering guidance in the digital process control system, hardware, or software areas. This programmatic area was addressed by a licensee problem report (PR NO. 95.0360), written during the inspection, that will start the corrective action process.

The digital system sample rate and execution time were not specified or analyzed. This was considered a weakness as far as identification of design inputs for digital process control systems was concerned. The sample rate and execution time are unique to digital systems and if not properly specified or analyzed, can be a major factor in the improper performance of an analog-to-digital upgrade. In the recirculation pump speed control case, the system response is slow and is rate-limited so that the vendor standard sample rate and execution time will most likely not cause improper control system performance. If improper system performance causes unsafe conditions to be approached, the totally independent safety-related reactor protection system is designed to actuate and shut down the reactor.

The BECo modification engineering team did not have access to independent software or digital control systems expertise. Consequently, they relied on the vendor judgement with respect to digital system software design analysis and had no independent design review in those areas. This is considered a weakness for those digital modifications that will not be maintained by the licensee's computer systems group. In the recirculation pump speed control case, the BECo design team attended a vendor class to learn some of the programming techniques and were able to understand the vendor software enough to recognize and change possible functional conflicts.

4.5.5 Software Configuration Management

- **Software Design Change Control**

The inspectors reviewed the licensee's design change control process to verify accurate translation of software parameter changes to supporting documents. Changes to the original design package are initiated through Field Revision Notices (FRN.) The inspectors reviewed nineteen FRNs and categorized them as follows: three FRNs resulted in software configuration database changes; eleven FRNs involved wiring and cabling changes; three FRNs provided additional information about the vendor design; and two FRNs clarified instructions in the testing procedures.

The inspectors reviewed the three FRNs that resulted in software database changes to document No. M1EA67, "Recirculation Pump Speed Control System Loops

A & B Program Configuration." Revision B to the program configuration was initiated by FRN No. 94-35-13 that included: (1) limiter 2 runback setting reduction to 44% from 60%, as a result of PDC No. 94-21; (2) the non-linear controller block gain was increased to 0.1333 from zero, and window was decreased to $\pm$2.5% from $\pm$5.0%. Revision C to the program configuration was changed by FRN No. 94-35-14 that consisted of reducing the gain in the non-linear control block to 0.1325 from 0.1333. Although not thoroughly noted in this FRN, the inspector determined through interviews that this was a result of the granularity of the vendor design that allowed entries of numeric values only in multiples of 0.0025. Revision D to the program configuration was initiated by FRN No. 94-35-17 that reduced the speed limiter 1 runback setting to 25.75% from 26.0%, due to a tuning issue identified during testing. The inspectors traced the implementation of the above parameter changes through the revisions of the logic diagram, the software database, the vendor system description, the testing procedure, and the operator training module. The inspectors concluded that all of the software changes were properly translated into the supporting documentation.

The inspectors found that there was an additional design change that was not tracked through the FRN change process. During vendor factory acceptance testing, the licensee design engineer discovered a problem with the lack of a priority scheme between speed limiters No. 1 and No. 2. The vendor system description was updated to reflect the fact that speed limiter No. 2 now overrides speed limiter No. 1. The inspectors again traced the implementation of this change through the supporting documentation. The inspectors noted that the licensee's procurement specification (Attachment B to PDC 94-35) did not reflect this change. The licensee plans to update the procurement specification at the design close-out stage as part of Problem Report No. 95.0360.

- **Software Media Control**

The inspectors reviewed the licensee's control of the software database contents and associated disks. The original program configuration (Revision A) was entered into the document control center (DCC) through FRN No.94-35-03. The master configurator disk and the original database disk were also placed in the DCC vault. Until the modification is closed out, the design engineer has the sole responsibility of controlling the database modifications, maintaining the current version of the database disk, and maintaining the laptop computer used to configure the system. The design engineer does not maintain separate hard copies of each database revision. However, alterations to the database can be traced through the FRNs initiating the change. The design engineer also does not maintain separate copies of each database disk revision. Instead, he rewrites the previous disk with the updated database contents. The design engineer stated that he keeps the laptop computer locked in a file cabinet in his office, unless needed by the modification engineer to update the system.

Once the database disk has been updated to the FRN, the design engineer releases the database disk, the system configurator disk, and the laptop computer to the cognizant modification engineer. The modification engineer, who attended the vendor training, performs the actual download of the updated database disk to the system using the configurator. Immediately following the download operation, the engineer initiates the vendor checkpoint function to verify the accuracy of the download. He then visually compares the checkpointed system database to a printout of what resides on the database disk. He also compares these to the changes noted in the FRN. After completion, the disks and computer are returned to the design engineer. The inspectors verified that the changes to the database as noted in FRN No. 94-35-17 were correctly installed on Revision D of the disk by comparing the FRN with the disk contents print out.

When this design modification is completed, the latest revision of the database disk is planned to be controlled by the DCC, along with the master configurator disk. The laptop, used as the configurator tool, is planned to be turned over to the I&C Maintenance group. Any further changes to the system will be initiated through an FRN and performed by one of the three cognizant I&C technicians, who attended the vendor training.

The inspectors concluded that the licensee's method of software media control was adequate because the software database is not complex, the changes are small, the database changes are tracked in the FRNs, and the database can be reconstructed from the original document plus the FRN changes.

4.5.6 Training

- **Engineer, I&C Technicians**

The design team engineers, the test engineer and the I&C maintenance technicians attended a one week training session on the vendor digital controller as it was configured for Pilgrim. The course covered the hardware, software control blocks, and configuration programming using a configurator computer. Through interviews with the engineers, the inspectors determined that the training was necessary to understand the control block functions and configuration process. The inspectors concluded that the training transferred important software control block information to the engineers.

- **Plant Operators**

The inspectors went to the training center to verify that the current data base values for parameters were in the training documents and to verify that the differences between the analog and digital system were adequately covered. Classes, hands-on laboratory exercises, and some simulator exercises were being conducted for the recirculation pump speed control modification. The inspectors did not observe any scenario-based simulator training using the new equipment.

The inspectors verified parameters in Operations Procedure Number 2.2.84 "Reactor Recirculation System," Revision 48 (effective date May 5, 1995), step 4.2.4[2](d) through (g) "System Controls and Instrumentation." The values for the Startup Generator Signal, Speed Limiter No. 1, Speed Limiter No. 2, and Rate Limiter matched the corresponding values described in the revised FSAR for PDC-35 and the current software program configuration document M1EA67, "Recirculation Pump Speed Control System Loops A&B Program Configuration," Revision D.

The inspectors determined the differences between the analog design and the digital replacement by examination of the purchase specification, vendor manuals, drawings, and interviews. The new digital operator display does not drop to zero when an analog output current loop is opened, which is one difference from the analog design. Another difference is that there are three bargraph displays on the display module face, but only one is active; the active one is denoted by an illuminated dot indicator at the top of each bargraph. The dot illuminates over a bargraph when a pushbutton on the display front panel is depressed. An alphanumeric readout indicates the digital value of the selected bargraph. A major difference is the way the variable is controlled by up/down pushbuttons that are time sensitive. The longer the pushbutton is depressed, the faster the selected variable will change.

The inspectors verified that the new alarms and the differences, with one exception, were recognized by the training staff and incorporated into the classroom, practical laboratory and simulator classes. The one exception was that the training staff were not aware that the bargraph display and the alphanumeric readout will not drop to zero when the output loop is opened. The I&C engineer stated that he would inform the training staff of this output loop failure mismatch with display indications.

The inspectors concluded that the significant differences between the analog design and the digital design for the plant operators were addressed by the combination of classroom, laboratory, and simulator exercises.

4.5.7 Walkdown

The inspectors walked down the installation of operator displays on the control board, the digital controller cabinet, and the recirculation system motor-generator room. There were HFA type electrical relays installed under the digital controller card nests. The I&C engineer stated that the AC relays were not expected to operate intermittently during normal operation, so this would minimize EMI threats from the relays.

The inspectors walked down the storage of the disks in the document control center vault. The original software disks were in the vault and controlled, but subject to damage because of inappropriate handling precautions. The two disks were clamped together by a heavy duty two inch binder clip. This was addressed by the licensee writing a problem report (PR NO. 95.0357) to initiate corrective action for update of disk handling procedures and check the master disks for any damage.

4.5.8 Management Oversight

The management selection of a conservative approach to the selection of the system to be upgraded, the experience of the design team personnel with the analog system, and the selection of a nuclear experienced vendor with a software V&V program and EMI testing, were considered positive factors for this modification.

The design engineer, the design review engineer, and the system engineer were not familiar with digital systems, although they were very familiar with the analog system. The engineering design guides did not cover digital control hardware and software design input criteria. The I&C division management sought software expertise during the conceptual stages from the computer systems supervisor, but was unsuccessful. Because the upgrade would not be maintained by the computer systems group after turnover, the software guidance could not be made available. This caused the I&C division manager to treat the recirculation system upgrade as a "pilot" of digital upgrades for process control systems. The major design parameters for digital control systems design were not specified as requirements to the vendor. The design engineers found out important software information too late in the design cycle. The recirculation system has a slow response and is rate-limited, so this compensated for the late software information. The lack of design guidance for digital upgrades means that important considerations unique to digital software-based systems could be overlooked by engineers not familiar with digital control system engineering. This weakness in the design guidance area shows that management did not fully evaluate the need for software expertise or digital control system guidance for the engineering staff.

4.5.9 Conclusion

Overall, the engineering for the recirculation pump speed control digital upgrade modification was performed generally in regard for plant safety and reliability. Because of the conservative approach to the analog-to-digital upgrade, the findings and weaknesses described above should not impair control system performance. Weak management attention was noted with respect to appropriate guidance and procedural infrastructure for digital upgrade modifications.

4.6 Low Pressure Turbine Replacement Modification

BECo installed a modification that replaced both low pressure turbine rotors, including the buckets, inner casings and the L-0 and L-1 diaphragms along with some extraction steam piping, expansion bellows and wafer check valves. The turbine was replaced because of a generic stress corrosion cracking problem of the shrunk-on wheel axial keyways and stress corrosion cracking at the wheel dovetails near the bucket entry slot. There was significant erosion corrosion of the inner casing and of the L-0 and L-1 diaphragms.

The safety concern with this cracking is the resultant increased potential for a turbine rotor failure. This issue was addressed generically by the NRC in NUREG-1048, Probability of Missile Generation in GE Nuclear Turbines. The analysis considered two potential shrunk-on wheel failure mechanisms, a brittle fracture due to the growth of keyway stress corrosion cracks to critical size, burst and generated missiles at normal operating speed; and, a ductile tension failure of the wheel that could occur during an overspeed event.

The inspector observed work on the turbine replacement at various times during the refueling outage for personnel radiation protection and personnel safety. There were no significant issues identified. The inspector also reviewed safety evaluation, No. 2909, that accompanied plant design change 94-16. The evaluation concluded that an unreviewed safety question did not exist in accordance with 10 CFR 50.59.

The replacement rotors are boreless monoblock rotors, that are more resistant to stress corrosion cracking than the original shrunk-on wheel rotors. The new inner casings are 1.25% Cr, which is more resistant to erosion corrosion. The L-0 and L-1 diaphragms are 12% Cr for the same reason. The monoblock rotor design was chosen to keep material stresses to a minimum and oxygen concentration mechanisms are eliminated to increase resistance to stress corrosion cracking. The tangential entry dovetails are shot peened to result in compressive surface residual forces, therefore improving resistance to stress corrosion cracking.

General Electric considers that the monoblock design eliminates the brittle fracture failure mode, the ductile failure is controlled by the probability of a turbine overspeed transient. General Electric estimates the probability of a complete control system failure as 10E-07 to 10E-08. The replacement rotors were balanced and brought to 20% overspeed by the manufacturer. There will be a change to the Pilgrim Station Updated FSAR because of this design change to state that inspection of the three principal turbine sections would normally be accomplished every ten years. This was changed from a complete inspection accomplished over a period of four major refueling outages.

5.0 PLANT SUPPORT (71707, 71750, 92904, 83729, 83750-2)

5.1 (Closed) Unresolved Item 50-293/95-07-01, Control Of Special Nuclear Material, Violation 50-293/95-09-03 (Open)

The last routine resident inspector report (IR 50-293/95-07, Section 5.2) documented the results of a BECo semi-annual audit of special nuclear material (SNM). BECo informed the resident inspectors on March 29, 1995 of seven missing nuclear detectors. On March 31, 1995, six of these detectors were found onsite as part of a detailed search effort. On April 6, 1995, BECo reported the remaining detector, a non-irradiated intermediate range monitor (IRM), as missing SNM to the NRC Operations Center pursuant to 10 CFR 50.72.

As the search continued for the missing IRM, plant management implemented several short term corrective actions including the assignment of a new SNM custodian, establishment of a locked storage area for portable non-fuel SNM not stored in the spent fuel pool and provisions for pre-work briefings for any activities associated with SNM. When transferring portable SNM to the new storage location on April 6, 1995, reactor engineers discovered that a fuel loading chamber (FLC) detector, no. 6578997, was not inside of its outer canister, otherwise referred to as a dunking chamber. The FLC contains approximately 1.2 grams of Uranium-235. This FLC had been used in the reactor core during a previous refueling outage. FLCs are used during refueling operations to measure neutron flux levels in the reactor core. FLCs are inserted in a single blade guide and lowered into the reactor core to be used in lieu of a source range monitor. Plant management developed a search plan to locate the missing FLC. The inspector, along with the plant manager, visually examined the new portable SNM storage area.

On April 19, 1995, a BECo representative sent to American Ecology, a nuclear metals processor located in Oak Ridge, TN, found the missing FLC, which was found inside of a dunking chamber. On April 20, 1995, the INS Company, a nuclear laundry facility located in Springfield, MA, located the missing IRM in a lint screen of a commercial dryer. BECo returned the missing FLC and IRM detectors back to the Pilgrim site. A radiological survey of the FLC showed the dose rates were less than .1 mR/hr (gamma), with the highest on-contact readings of 400 counts/minute (gamma). The inspector determined that no radiological consequence to the public resulted from the misplaced SNM. The BECo search effort successfully located the missing SNM, which remained in the nuclear waste stream. However, the search effort consumed 3,000 to 4,000 man-hours, 150 millirem of radiation exposure, and one minor personnel contamination.

The inspector determined that BECo performed well by self-identifying and reporting the misplaced SNM, developing a thorough search plan that eventually led to the recovery of the lost SNM, and identifying the missing FLC as part of the short term corrective actions. Also, the evaluation of the need to physically audit the portable SNM stored in the spent fuel pool was noteworthy. Although BECo self-identified this problem, licensee internal records indicate a repetitive problem in this area. The amount of uranium-235 contained in the misplaced detectors was not enough (i.e., less than 15 grams) to be classified as low strategic significance as defined in 10 CFR Part 73.2. None the less, the inspector concluded that the loss of control of SNM that resulted in an IRM and FLC inadvertently leaving the site boundary was a violation of 10 CFR 70.51(b)(1), which requires licensees to keep records showing the receipt, inventory (including location), disposal, acquisition, and transfer of all SNM in his possession. **(Violation 50-293/95-09-03)**

The inspector reviewed the sequence of events leading to the misplaced IRM/SRMs and FLC, which are discussed separately. On March 2, 1995, a material balance area (MBA) transfer form authorized the move of 6 IRMs and 2 SRMs from the Instrument and Controls (I&C) lab to the refueling floor in the reactor building. I&C workers cut seven of the eight detector tips from the detector cable assemblies with the intention of placing the cut detectors into the spent fuel pool. The eighth detector, an SRM, was not cut and remained in the I&C lab. I&C workers placed the seven cut detectors into a magenta bag with one SNM identification tag. The magenta bag containing the detectors was moved to the refueling floor, last seen laying on the floor on March 24, 1995. BECo waste processing workers recalled removing the detectors magenta cloth bag. The cloth bag was placed with clothing to be washed, while the detectors were treated as low level radioactive waste. Six of the detectors were found in trash bags at the trash compactor facility on-site. The last detector was located at a nuclear laundering facility located in Springfield, Ma.

An operations section evaluation developed a sequence of events for the missing FLC. On March 23, 1993, I&C technicians prepared the subject FLC for use in refueling outage no. 8. Due to a failed leak test, the dunking chamber needed to be replaced. The technicians removed the FLC and inserted the detector into a new dunking chamber. This created a new core-ready package with approximately eighty feet of air-hose. I&C technicians did not label the new core ready package with an SNM identification tag, did not remove the SNM identification tag from the old dunking chamber, and failed to inform the SNM custodian of the creation of a new core-ready package. The review speculated that the activities associated with dismantling the south refueling floor tool crib for outage preparation inadvertently resulted in the new core-ready package being discarded as general waste.

BECo identified several causes for the misplaced SNM. For the IRM/SRMs, the licensee determined the causes were the failure to individually label the cut detector tips, the lack of a work plan to control the detector cutting activity, and several refueling floor radiation protection technicians handled the bag without realizing that IRM/SRMs are SNM requiring special controls. The causes of the misplaced FLC, again involving I&C technicians, have been discussed earlier in this write-up. A BECo review of the SNM control "operating experience" found a few instances of events involving SNM control. For example, in 1991, a FLC was misplaced and later found. In 1993, a dunking chamber was relocated without proper program controls. Lastly, the portable non-fuel SNM stored in the spent fuel pool has not been physically audited in approximately 5 years. The BECo audits have relied on a review of paperwork.

Although no threat to the public existed, the lost SNM resulted in an extensive BECo search effort that used approximately 115 millirem of radiation exposure.

5.2 Radiation Protection

5.2.1 Organization

The Radiation Protection (RP) Section was reorganized since the last HP inspection. A new Radiation Protection Manager (RPM) was appointed effective January 1, 1995. The new RPM's qualifications were reviewed and found to meet the requirements for this position as contained in Pilgrim Technical Specifications and in ANSI N18.1-1971. In addition, the Radiological Operations Support Division Manager position was deleted (the current RPM's former position) and the dosimetry operations were transferred to the Radiological Support Division. No discrepancies were noted with respect to these changes.

The expanded outage RP operations staff included 59 contract RP technicians, 11 BECo RP technicians, and 9 BECo RP supervisors. All contractor RP technicians were qualified by the licensee as senior RP technicians. The inspector reviewed selected résumés and verified that those selected met the experience qualifications specified in ANSI N18.1-1971. No discrepancies were noted. During observations of RP technician performance in the plant, the inspector did not observe any performance deficiencies related to RP technician training or qualifications.

5.2.2 Problem Reporting System

The licensee's problem report program was reviewed with respect to the licensee's effectiveness in resolving radiological events, and for its use in making program improvements. One recurring radiological problem was reviewed by the inspector to measure the program's performance strengths and weaknesses.

The licensee continues to experience a chronic problem with contaminated tools being found outside of the radiologically controlled area (RCA). This situation has existed for several years and was previously designated by the licensee as a "severity level I problem report". Such issues are addressed by utilizing a root cause analysis, and comprehensive treatment of the root cause(s) and all contributing causes. This was done, but several more instances have again been reported in 1995. The problem has again been assigned as a severity level I problem report. At the time of this inspection, the problem report was still open. The inspector reviewed the initial corrective action recommendations and determined that these recommendations were not significantly different from the corrective actions implemented previously.

During this inspection, the inspector expressed concern about the need for additional corrective action recommendations to address the tool control issue. The licensee indicated that a special multi-disciplinary task force had been formed in late 1994, to restudy the tool control issue. The task force also reviewed the approach taken by another utility. Some significantly different ideas were proposed to the Plant Manager that, at the time of the inspection, had not been endorsed. The Vice President of Nuclear Operations endorsed the ideas proposed by the special task force. These actions include substantially increasing the size and layout of the contaminated tool issue area, separate issue and return windows, and an integral tool decontamination shop. In addition to providing a more customer oriented tool issue and return area, the plans include the use of a bar code reader system to provide accountability for tools issued. These plans represent the long-term corrective actions.

In order to correct the problems at this time, particularly during the current outage period, the licensee performed a "sweep" of all RCA outage work areas, reclaimed any unused tools, and restocked the contaminated tool issue point. Also, those tools inside the RCA that were not already painted with magenta paint were painted to provide a visible indication that they are for RCA use only. The inspector was satisfied that appropriate attention and actions had been and would be taken with respect to short and long-term corrective actions.

The licensee's threshold for identifying and addressing problem report issues was excellent. The recurrence of the contaminated tool control problem was reported and there was a good record of these problem reports included in the problem report resolution process. The licensee used the multi-discipline group, the Problem Assessment Committee (PAC), to analyze the cause(s) of a reported problem. The PAC worked by assigning a plant individual to propose corrective actions. The PAC subsequently convened to either accept or reject the proposed corrective actions. (Problem analysis in this area did not reflect a thorough review.) For successful resolution of the tool control issue, outside of the problem report program, the Plant Manager formed a one time, ad hoc group to pool talents in search of solutions from both inside and outside of the licensee's organization.

In summary, the inspector determined that while the problem report program appears to be an excellent program for identifying and reporting Station problems, it does not appear to have been fully effective at addressing the corrective actions needed to fix the problem of contaminated tools being removed from the RCA. The licensee stated that the inspector's finding would be considered.

5.2.3 External Exposure Control

The inspector made tours of the major radiological work areas during the inspection and observed work in progress, observed postings and control over work areas, reviewed radiation work permits, and made independent radiation surveys in areas for comparison with licensee surveys and for evaluation of ALARA shielding.

The refueling floor was well posted with various clean areas, contamination areas, hot particle control zones, and foreign material exclusion zones. Contamination levels were low and radiation levels were also very low. At least one RP technician was available on the refueling floor during the inspector's tours who was knowledgeable about the work being performed and was sensitive to the radiological hazards, for example, the surveying of tools as they were removed from the reactor cavity pool. Licensee surveys were comprehensive and complete. Radiation work permits (RWPs) generally lacked specific radiological controls, despite some being well written.

The drywell was controlled as a locked high radiation area, which required timekeeping controls and intermittent RP technician coverage for entry. The drywell RP control point provided effective radiological condition briefings for workers entering the area. A RP technician was generally staged just outside the drywell and made occasional tours into the drywell to ensure timekeeping controls were met and to provide radiological surveys as necessary. The drywell was posted for informational purposes, with generally one low dose waiting area designated on the two main platform levels. The licensee had made a good effort to shield most of the recirculation piping system with temporary lead blankets. One-eighth inch to three-eighths inch thickness of lead was generally provided. General area dose rates remained approximately 100 mrem/hr near the shielded recirculation piping, while the dose rate dropped off to 20 mrem/hr with distance from this piping system. The inspector noted two areas on the 41-foot elevation (recirculation inlet piping level) in the 20 mrem/hr area. These were near the outside shell of the drywell, where 10-foot long gaps in platform grating created a drop to the 23-foot elevation platform. This observation is discussed further in Section 5.2.6 of this report.

The drywell RWPs generally were weak in specifying anything but generic radiological control requirements. For example, insulation removal work did not indicate the need for an RP technician to perform smear sample surveys after removal of insulation. Also, for work under the vessel involving local power range monitor cable, the RWP did not specify relocation of personnel dosimetry to the head. However, licensee surveys were adequate and the radiological control of work in the drywell was performed very well.

During the inspection, the "A" RHR loop was undergoing various maintenance activities. The inspector observed adequate postings in the "A" RHR Quad area. Temporary lead shielding was applied only to the lower horizontal RHR piping. It had no direct affect on the general area dose rates in this area and a negligible effect on exposure reduction. The inspector determined that the shielding installation was not fully effective. The licensee determined that most of the scheduled outage work in the "A" RHR Quad had been completed and, therefore, further shielding enhancements, at this time, would not be of benefit.

The torus room was used as a storage location for scaffolding and a transit path for many maintenance areas in the reactor building basement. Through independent surveys, the inspector determined that the torus was 60-100 mrem/hr at contact due to sludge deposited in its bottom. Because of this source term, the reactor building basement general area dose rates were 20-40 mrem/hr. Through the examination of licensee records, the inspector determined that greater than 11 person-rem had been spent on performing torus weld inspections approximately midway through the outage. The inspector discussed with the licensee the opportunity for exposure reduction through desludging of the torus. The licensee indicated this would be considered for the next refueling outage. Generally, postings were good and RP technician control of work activities in these areas was also good. No discrepancies with external exposure control were noted except for the high dose rates in certain areas and the cited weaknesses in radiological work instructions on the RWPs.

Through interviews with RP technicians and supervisors and observations by the inspector, the inspector determined that the licensee was exercising better radiological controls than were specified on the RWPs. However, the lack of documentation of radiological control requirements in the RWPs requires the RP technician covering the work to impose additional work requirements and receive full cooperation from the workers. The inspector noted that the ALARA work requirements were contained on in-process control sheets that were included with the applicable RWP. Shielding and containment/ventilation requirements were also contained on these in-process control sheets. This was an improvement over the previous outages when the ALARA requirements were only found in the maintenance work packages and were not generally available to the RP staff. The inspector discussed with the licensee additional efforts to capture the radiological control requirements on the RWPs to optimize the radiation protection of the workforce.

5.2.4 Internal Exposure Controls

The inspector reviewed air sample results, air sample-based internal exposure tracking results, bioassay measurement results, and final internal exposure assessment reports.

The inspector's review of licensee air sample data determined that approximately 30 air samples were taken each day of the outage and that approximately 10% of these indicated an airborne radioactivity area (i.e., >0.3 derived air concentration (DAC), as defined by the licensee). Approximately 0.5% of the air samples were above 1 DAC, but less than 10 air samples indicated DAC level greater than 10 DACs. The inspector selected several of these higher air samples and investigated the internal exposure assignments to workers in the applicable work areas. In each case, the inspector found DAC-hour tracking sheets calculated for each of the airborne radioactivity area air samples. In some cases, respiratory protection was provided and in others it was not. The inspector noted that any internal exposure greater than 4 DAC-hours was tracked. Direct bioassay measurements (or whole body counts) were performed as a result of DAC-hour tracking indications and personnel contamination indications. On average, approximately one whole body count measurement was performed each day for investigational purposes in response to either contamination monitor alarms or high air sample indications during the outage. The inspector reviewed several of the investigations and noted that followup measurements were made for all positive whole body counts and thorough internal exposure assessments were performed by radiological support group specialists. At the time of this inspection, none of the outage internal exposure assessments resulted in exceeding the minimum 100 mrem internal exposure threshold the licensee uses for officially recording internal exposures. Therefore, there had not been any recorded internal exposures. The inspector determined that the internal exposure control program resulted in limiting the extent of airborne radioactivity areas and appropriate internal exposure tracking and assessment were performed. No discrepancies were noted.

5.2.5 As Low As Is Reasonably Achievable (ALARA)

The inspector reviewed the licensee's exposure reduction program through interviews with licensee's staff, review of documentation, and through independent in-field survey measurements.

The licensee established a very challenging ALARA goal of 270 person-rem for the 55-day refueling and maintenance outage. As of day 25 of the outage, 208 person-rem had accumulated and the licensee predicted at least a 20 person-rem overrun of the goal. The licensee stated that additional emergent work, delays with refueling and higher doses due to in-service inspection, all contributed to the projected overrun. Licensee management has adopted a policy of holding work groups accountable for their estimated exposure by RWP. When the RWP exposure budget was exceeded, the work was generally put on hold and the work group was required to justify the need for additional dose prior to continuing the work. In some cases, the ALARA exposure estimate was found to be incorrect and was revised. In other cases, dose was borrowed from work that came in under budget or from future work, with the expectation that the overall work group dose would come in under budget. The inspector considered this a very good ALARA initiative.

Another licensee initiative was designed to encourage the outage workforce to reduce personnel exposures. The licensee implemented an ALARA lottery on April 17, 1995, that consisted of a weekly drawing from the individuals who had worked under an RWP and had finished below its estimate. Once a week, one individual would be selected and given a significant cash prize. This is indicative of management support in encouraging outage workers to reduce their exposures and is considered a good initiative.

The licensee's ALARA staff consisted of two ALARA specialists during non-outage periods, complemented by two additional specialists and eight ALARA technicians during this outage. Some of the ALARA exposure reduction efforts initiated by this group during this outage included:

- hydrolasing of both the east and west control rod drive scram discharge headers that, based on the inspector's review of licensee surveys, indicated a dose reduction factor of 2;
- hydrolasing of the reactor water clean-up (RWCU) suction line to benefit both the drywell and RWCU heat exchanger room work (which also resulted in a dose reduction factor of 2);
- several reactor disassembly/reassembly work method enhancements;
- and temporary shielding provided for major work areas (e.g., drywell, RWCU heat exchanger room, "A" RHR Quad, and other miscellaneous plant locations).

The licensee developed an outage exposure accumulation per day, based on the original outage schedule, that was used as the daily outage performance criterion by licensee management. The outage exposure accumulation was plotted but was not tied to the schedule or updated if emergent work or schedule changes were made. Therefore, it did not represent an accurate standard of performance, particularly as schedule changes resulted in departures from the original outage schedule. The ALARA group provided a daily RWP status report that listed all RWPs that had accrued ≥80% of the estimated or budgeted dose. This report triggered the initiation of an ALARA in-process review and the information was used by licensee management to review significant outage work as it approached its dose budget value and bring added attention to the ALARA performance of select jobs.

In general, the licensee provided good review and use of ALARA techniques in the outage work activities. The ALARA requirements were specified in the maintenance work packages and summarized on an in-process control sheet that accompanied the RWP. Hydrolasing of significant work-related piping systems was effectively used by the licensee. Temporary shielding of the recirculation piping and the reactor water clean-up systems resulted in significant exposure savings during the outage. Other exposure reduction opportunities existed which included: desludging of the torus, installation of permanent platforms in routinely scaffolded areas (e.g., the RWCU heat exchanger room), better pre-planning and work practices which could have lowered the total dose expended (approx. 25 Rem) on replacing the reactor water cleanup inside containment isolation valve 1201-2 and the use of permanent shielding in plant areas. The Station ALARA priorities continue to be based on individual maintenance tasks. Typically, several tasks are performed in most work areas during an outage and laydown and transit areas are shared by multiple work groups performing multiple tasks. In general, the licensee will continue to undervalue the worth of exposure reduction initiatives until the cumulative exposure of all tasks performed in a work area are evaluated during the entire outage. In some cases (i.e., for repetitive tasks that are performed each outage), work area exposures should be represented by life-of-the-plant exposure estimates. Once the full exposure potentials of Station areas are realized, appropriate licensee resources and priorities can be applied with resultant better focused exposure reduction efforts.

5.2.6 Worker Safety Conditions

The inspector reviewed most major outage work areas. Radiological postings and work area conditions were generally good. Inside the drywell at the recirculation inlet piping level, the inspector noted that there were two areas approximately 10 feet long near the outer drywell shell where there was no grating or barricade to prevent workers or tools from falling 20 feet to the grating level below. The area with missing grating was the desirable lower dose rate transit path around this elevation of the drywell and was in an unsafe condition. This occupational safety concern was presented to the licensee by the inspector. It was promptly investigated, but was slow to be evaluated. The evaluation resulted in an initial decision to take no corrective action. After repeated requests by the inspector to determine the status of the safety evaluation, the inspector was told that there were only 13 days of drywell work left and it would not be worthwhile in the interest of minimizing exposure to install temporary planks in the grating gaps. Apparently, there had been no discussion or consideration of posting the areas as an occupational safety hazard. After the inspector requested the area to be posted and workers warned of the safety hazard, the licensee promptly posted these areas - approximately one week after the safety hazard had been reported.

The inspector determined that the licensee's response to this safety concern was narrowly focused. After the inspector identified the safety concern, the licensee's evaluation determined that the exposure savings in using the lower dose rate area near the outer drywell shell versus the higher dose rate transit path near the recirculation system piping had been evaluated against the cost in radiation exposure to install planking over the gaps. The risk of injury had not been considered.

When the inspector discussed this matter with the licensee, the licensee indicated that the Station Safety Organization management had been inadvertently bypassed when the matter was evaluated and that resulted in the slow response. The licensee stated that, had the appropriate safety supervision been involved, more expeditious evaluation and appropriate actions would have taken place. The inspector suggested further review of this matter by the licensee. In particular, consideration should be given to feedback to the initiator of a safety concern and to assurance that safety concerns are passed promptly to the appropriate personnel.

5.2.7 (Closed) Inspection Follow-up Item 50-293/94-15-01

During several previous inspections[1] issues were raised concerning the proper disposition of radiological problem reports. During NRC Inspection No. 50-293/94-15 conducted during July 18-22, 1994, the licensee committed to enhancing the classification of radiological problem reports to require root cause analysis and multiple cause corrective actions for those events that result in unplanned radiation exposures.

During this inspection, the inspector reviewed a procedure entitled, "PAC Work Instruction" Rev. 0. The instruction provides guidelines for the types of radiological problem reports that normally require an in-depth or root cause analysis, such as; unplanned internal or external exposures, loss of control over radioactive material, potential unmonitored releases to the environment, and major radiation protection procedure violations. This document requires each Problem Assessment Committee (PAC) member to read this instruction prior to participating in PAC meetings. The inspector attended a PAC meeting during this inspection and verified that the PAC members exercised an appropriate sensitivity to radiological problem reports that were presented, and properly evaluated the multiple causes associated with those reports. This item is closed.

5.3 Security

The inspector observed security guards perform routine and outage duties in a meticulous manner. A tour of the protected area was performed with the security manager including an inspection of the common and secondary alarm stations, and the armory. Entries in the security log were reviewed. Compensatory security watches stationed at the drywell access and the "A" EDG room remained alert and aware of the attendant responsibilities. Control of the increase in the contractor workforce was effective.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (40500, 92902, 92903)

6.1 Management Effectiveness

Management oversight of refueling activities was clearly evident. The inspector observed managers tour the plant including the control room, drywell and refueling floor. At the morning plant manager's meeting, discussions clearly prioritized safety over schedule pressure. For example, management decided to replace all scram pilot valves during the outage in lieu of replacing the periphery ones as on-line maintenance. Also, the management pursuit of the indication of a possible crack on the 0 degree core shroud access cover weld was noteworthy. Although an enhanced visual inspection found no obvious depth to the indications, BECo elected to hire a contractor to perform a detailed ultrasonic inspection. The inspections characterized the indications as having no depth and as non-relevant. The decision to perform the ultrasonic inspection eliminated any uncertainty as to the characterization of the flaw. Further, plant management stopped refueling

---

[1] NRC Inspection Report Nos. 50-293/93-10; 50-293/93-16; and 50-293/94-03

operations to develop lessons learned from two operator errors involving inadvertent control rod actions. These examples demonstrate a strong management commitment to nuclear safety.

The installation of a new, upgraded control room alarm system with redundant and diverse power supplies provided control room operators with increased capabilities with better consideration for human factors. The digital speed controller modification of the reactor recirculation pump motor generator sets and the new control room alarm system had been installed in the plants training simulator before the outage. This allowed the operators to familiarize themselves with the characteristics of the new equipment before plant start-up. These plant modifications, and respective simulator upgrades, directly enhanced the control room environment.

Excellent problem identification and reporting by plant workers was evidenced by the initiation of several problem reports each day. Critiques were held, as necessary, to develop an initial sequence of events, implement short term corrective actions and assess the safety significance of each problem. Opportunities exist for management to implement more effective and timely corrective actions at an earlier stage. An example of this includes the issue of contaminated tool control discussed in section 5.2.2. Another example involves the buzzing sound originating from the "A" EDG, which is discussed in section 4.3 of this report. Further, the inspector noted that several work activities resulted in the need for maintenance rework. This opportunity to improve the effectiveness and timeliness of corrective actions was also discussed in BECo quality assurance audit 95-01A, dated April 25, 1995. Plant management expects that the backlog of problem report evaluation and corrective actions will begin to decrease after the outage.

The inspector observed that the outage production work control scheduling was incomplete or in error and process planning for availability of parts was weak. In summary, BECo performed well during RFO10 by emphasizing reactor safety and the need to do the job right the first time. Opportunities exist for further improvement.

6.2 Review Of 10 CFR 50.59 Safety Evaluation Of Pilgrim Core Shroud Repair

During Pilgrim refueling outage No. 10, a design change was implemented that provided a permanent repair for the core shroud in the reactor vessel. The repair structurally replaces all of the shroud circumferential welds by installing stabilizers consisting of tie rods and lateral acting springs at four locations on the outside of the shroud in the jet pump annulus. The circumferential welds have been determined to be susceptible to intergranular stress corrosion cracking (IGSCC) as discussed in NRC Generic Letter 94-03, and the licensee chose to install the preemptive repair in lieu of continued inspection and analysis. The preemptive repair was made in accordance with 10 CFR 50.55a(a)(3)(i) as an alternative repair which was evaluated and found acceptable by the staff in a Safety Evaluation (SE) dated May 12, 1995. The licensee performed its SE of the core shroud repair activities in accordance with 10 CFR 50.59 requirements. The staff has reviewed the licensee's documentation for the SE to verify its adequacy for addressing the 10 CFR 50.59 requirements. The specific documentation reviewed included licensee's

SE No. 2926 (Document No. PDC 94-43) and the attachments thereto, which were signed and approved on March 27, 1995. The guidance of Inspection Procedure 37001 (10 CFR 50.59 Safety Evaluation Program) was used by the staff during its review.

Based on its review, the staff concluded that the licensee has complied with the regulatory requirements regarding evaluation of the core shroud repair plant modification. In accordance with 10 CFR 50.59, the licensee has determined that neither a change in the technical specifications (TS) as incorporated in the plant license nor an unreviewed safety question exists. The staff agrees with this determination. Consequently, no license amendment pursuant to 10 CFR 50.90 was necessary.

7.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (71707)

7.1 Routine Meetings

Two resident inspectors were assigned to the Pilgrim Nuclear Power Station throughout the period. The inspectors performed back shift inspections on April 4, 8, 20, 24 and 27 and deep back shift inspections on April 17, 19 and 20. On April 21, 1995, Messrs.R. Wessman and E. Carpenter and Ms. K. Kavanaugh, all from NRR, visited the site to observe a portion of the core shroud pre-emptive repair. This report also integrates the findings of several region based inspections.

Throughout the inspection, the resident and region based inspectors held periodic meetings with plant management to discuss inspection findings. The NRC staff also held an interim public exit meeting on May 11, 1995 at the Chiltonville Training Center (Attachment 1 - Handout from Licensee). The inspector presented the findings and assessments to the senior vice president and his staff. No proprietary information was covered within the scope of the inspection. No written material regarding the inspection findings was given to the licensee during the inspection period.

7.2 Other NRC Activities

On the night of May 11, 1995 from 7:00 p.m. to 10:00 p.m., members of the NRC, led by Messrs. R. Cooper (Region I) and J. Zwolinski (NRR), conducted a meeting at the John Carver Inn located in Plymouth, Ma. The NRC received input from the public and answered questions concerning the performance of BECo during RFO 10. The documentation of this meeting including answers for requested information will be provided by a separate letter placed onto the docket.

ATTACHMENT 1

BECo/NRC MEETING HANDOUT

MAY 11, 1995

SEE DOCKET ROOM FOR ATTACHMENT

August 4, 1995

Mr. E. Thomas Boulette, PhD
Senior Vice President - Nuclear
Boston Edison Company
Pilgrim Nuclear Power Station
Rocky Hill Road
Plymouth, Massachusetts 02360

SUBJECT: PILGRIM INSPECTION 95-13

Dear Mr. Boulette:

From May 17, 1995 through July 5, 1995, Messrs. R. Laura and A. Cerne of this office conducted a resident inspector safety inspection at the Pilgrim Nuclear Power Station, Plymouth, Massachusetts. Areas relevant to the health and safety of the public examined during this inspection are described in the enclosed report. Our findings were based upon observations of performance and independent evaluations of safety systems and quality records. The preliminary results have been discussed with Mr. Leon Olivier and other members of your staff at the conclusion of the inspection.

Operators performed generally well during power ascension following the completion of a challenging refueling outage (RFO10). Special tests, such as the reactor vessel leak check and the turbine vibration and overspeed test, were controlled in a deliberate manner with excellent operator command-and-control. Plant management oversight and involvement in power ascension activities was considered a strength. Also, the application of industry operating experience and lessons learned in several instances contributed to the defense-in-depth reactor operation philosophy. For example, the application of industry experience involving reactivity management for a "soft start-up" mitigated the potential for pellet clad interaction fuel rod failure. Another example was the turbine special test which delineated specific abort criteria to trip the turbine at specified vibration levels. Lastly, we commend the reactor operator who exhibited a questioning attitude when he noticed improper operation of the controller, prior to the post-modification calibration, for the generator stator cooling system temperature control valve. Collectively, these positive performance observations indicate that your staff has a good safety perspective.

In contrast, we note that opportunities remain to further improve performance to achieve consistent and superior performance. Our review of two operational events at the end of RFO10 determined that ineffective communications between departments contributed to the chloride intrusion event and the "B" residual heat removal (RHR) pump run with the suction valve closed for a brief period of time. Operation of the "B" RHR pump with the incorrect system line-up had the potential to damage a safety related component. These two events, coupled with three other self-disclosing operational events of low safety consequence that occurred during the previous inspection period as

9508140264 — 3ff

Enclosure 2

documented in NRC Inspection Report No. 50-293/95-09, Section 2.2, indicated that operator performance during RF010 was not consistent with past good performance in the operations functional area. We suggest that your organization carefully review these operational events to develop and implement the appropriate lessons learned to improve future operator performance during transition periods from refueling to operational activities.

Sincerely,

Original Signed By:

James C. Linville, Chief
Projects Branch No. 3
Division of Reactor Projects

Docket No. 50-293

Enclosure: NRC Inspection Report No. 95-13

cc w/encl:
L. Olivier, Vice President - Nuclear and Station Director
T. Sullivan, Plant Department Manager
R. Fairbank, Manager, Regulatory Affairs and Emergency Planning Department
D. Tarantino, Nuclear Information Manager
D. Ellis, Acting Senior Compliance Engineer
R. Hallisey, Department of Public Health, Commonwealth of Massachusetts
The Honorable Therese Murray
The Honorable Linda Teagan
B. Abbanat, Department of Public Utilities
Chairman, Plymouth Board of Selectmen
Chairman, Duxbury Board of Selectmen
Chairman, Nuclear Matters Committee
Plymouth Civil Defense Director
Paul W. Gromer, Massachusetts Secretary of Energy Resources
Bonnie Cronin, Legislative Assistant
A. Nogee, MASSPIRG
Regional Administrator, FEMA
Office of the Commissioner, Massachusetts Department of Environmental Quality Engineering
Office of the Attorney General, Commonwealth of Massachusetts
T. Rapone, Massachusetts Executive Office of Public Safety
Chairman, Citizens Urging Responsible Energy
D. Screnci, PAO (2) All Inspection Reports
NRC Resident Inspector
Commonwealth of Massachusetts, SLO Designee

Distribution w/encl:
Region I Docket Room (with concurrences)
PUBLIC
Nuclear Safety Information Center (NSIC)
R. Conte, DRP
J. Shedlosky, DRP
H. Eichenholz, DRP
M. Kalamon, DRP

Distribution w/encl (**VIA E-MAIL**):
T. Marsh, NRR
R. Eaton, NRR
W. Dean, OEDO
Inspection Program Branch, NRR (IPAS)

DOCUMENT NAME: A:\PL9513.INS

To receive a copy of this document, indicate in the box: "C" = Copy without attachment/enclosure "E" = Copy with attachment/enclosure "N" = No copy

OFFICE	RI/DRP		RI/DRP		RI/DRP				
NAME	LAURA/RJC		CONTE/RJC		LINVILLE/PJC				
DATE	08/01/95		08/02/95		08/04/95		09/ /95		09/ /95

OFFICIAL RECORD COPY

U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.: 50-293

Report No.: 95-13

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

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: May 17, 1995 - July 5, 1995

Inspectors: R. Laura, Senior Resident Inspector
A. Cerne, Resident Inspector

Original Signed By: 08/03/95

Approved by: ______________________ ________
R. Conte, Chief Date
Reactor Projects Section 3A

Scope: Resident Inspector safety inspections were conducted in the areas of plant operations, maintenance and surveillance, engineering, plant support, and safety assessment/quality verification. A reactive inspection was performed on two operator performance issues to identify any commonalities in light of three operator errors made during the previous routine inspection period involving control rod latching and venting activities. Additionally, a review of the performance indicators listed in the maintenance improvement plan was performed.

Findings: No violations were identified. An inspector follow-item was identified to review the scaffolding structure in the "A" quadrant room (section 5.3). A self-disclosing event involving the "B" residual heat removal pump, which was run with the suction valve closed for a brief period of time, was dispositioned as a non-cited violation. An NRC identified issue involving missed senior reactor operator reviews for two safety related valve line-ups was also dispositioned as a non-cited violation. See the Executive Summary for an overall assessment of performance.

~~9508140285~~ 21 pp.

EXECUTIVE SUMMARY

Pilgrim Inspection Report 95-13

Safety Assessment/Quality Verification: Plant management involvement and the application of industry operating experience enhanced nuclear safety during the power ascension from the refueling outage. For example, the turbine vibration and overspeed testing, which incorporated industry lessons learned, was closely monitored by plant management. Also, the initiation of several major initiatives, new work control process, scheduling and plant material condition plan represent continued commitment to improving overall plant performance. Communications between departments was identified as an area for improvement to possibly reduce unplanned operational events. The identification of three problems (i.e, maintenance work request tag clearance, contaminated tool control labeling and two incomplete safety related valve line-up reviews) in implementing station programs represent opportunities for improvement .

Plant Operations: Operator performance was mixed. Near the end of the refueling outage, two operational events detracted from overall positive operator performance during a challenging refueling outage work scope. The two events involved a chloride intrusion event and running the "B" residual heat removal pump with the suction valve shut. A causal analysis of these two events found communications between departments weakened. In addition to these two issues, last inspection period, three other minor operational events (involving an inadvertent start of the emergency diesel generator, and two events involving control rods) reflected additional examples of weak communication. Also, these operational events indicated, that in a few instances during the refueling outage, operator performance was not consistent with previous good performance.

In contrast, operator performance during power ascension was deliberate and clearly focused on reactor plant safety. Industry operating experience recommendations for a "soft start-up" to mitigate the potential of fuel pellet clad interaction failure were implemented. Operators exhibited excellent command-and-control and experience during the conduct of major special tests including the turbine vibration and overspeed testing. A questioning attitude was exhibited by a reactor operator when he observed improper operation of the generator stator cooling system temperature valve controller. One minor issue was identified during start-up involving missed nuclear watch engineer reviews of two safety-related system valve line-ups. Overall, operators performed generally well during power ascension activities.

Maintenance and Surveillance: Instrument and control workers performed well during a troubleshooting activity involving a scram discharge instrument volume level element. The I&C division manager was observed at the work site providing effective guidance and support of the work. Excellent coordination and synergies between station departments were observed during the reactor vessel leak check. A weakness was identified in the area of clearing maintenance work request tags on plant equipment after work completion or after voiding of the maintenance request. A review of the maintenance performance indicators develope' response to the drywell-to-torus differential pressure transmitter plug violation (Inspection Report No. 50-293/94-26) determined that progress was made. While the individual performance matrix and maintenance program indicators provide good information, opportunities exist to include other valuable information such as performance-based observations for the matrix and maintenance rework for the program indicators.

Engineering: Engineering involvement in day-to-day plant operational activities was clearly evident during the plant manager's morning meeting, follow-up to the vessel flange leak detection alarm, and analysis of the motor operated valve dynamic test data for the reactor core isolation cooling turbine steam supply valve. The controls for foreign material exclusion during the refueling outage were properly implemented. For example, although the search for a socket and adapter that fell into the reactor cavity area did not locate the missing pieces, a problem report and lost parts analysis provided adequate justification for continued operation.

Plant Support: The administration of an emergency preparedness combined function drill on June 29, 1995 effectively exercised the station staff. The drill critique demonstrated an effective self assessment capability by determining an overall adequate level of performance with the identification of some opportunities for improvement. Based on the observations made during tours of the radiological controlled area, a difference existed between management expectations and program requirements for the marking of potentially contaminated tools. The initiation of a four year plant material condition upgrade plan represents a significant effort. The upgrade of the screenhouse began during this inspection period. Some areas in need of clean-up from refueling outage activities were observed. The radiological conditions (i.e, high radiation and contaminated) in the "A" and "B" quadrant rooms allow for poor worker accessibility. The east and west hydraulic control units remain as contaminated areas. However, progress was made during this inspection period in the decontamination of the reactor core isolation cooling turbine room. As a result of inspector findings in the area of plant housekeeping and scaffold installation in recovering from the recent outage, BECo plans to further review this area.

TABLE OF CONTENTS

DE...LS

1.0 SUMMARY OF FACILITY ACTIVITIES

At the start of the report period, Pilgrim Nuclear Power Station (PNPS) remained shutdown for refueling outage no. 10 (RFO10), which began on March 25, 1995. Operators completed reactor fuel bundle loading, shuffles, general reassembly and reactor cavity draindown during the end of the previous inspection period. After the reactor vessel head studs were torqued this period, operators performed a reactor vessel leak check on May 21, 1995 pursuant to ASME Code Section XI, Class I System Leakage Pressure Test. On May 24, 1995, an integrated leakage rate test of the primary containment was performed pursuant to technical specification surveillance requirement 4.7.A.2.a and 10 CFR 50, Appendix J. During plant start-up preparations, BECo made a 10 CFR 50.72 event notification (i.e., ENS 28875) to the NRC reporting an unplanned actuation of the primary containment isolation system. BECo later retracted the event notification because the system had been properly removed from service and the isolation actuated due to an invalid signal.

After completing the necessary start-up prerequisites on June 2, 1995, the operators placed the reactor mode selector switch to the "Start-up Mode" position. Later that night, the reactor was bought critical. On June 5, 1995, the operators placed the reactor mode selector switch to the "Run Mode" position. During high pressure core injection system testing, unplanned actuations of the drywell-to-torus and torus-to-reactor building vacuum breakers occurred. BECo made corresponding 10 CFR 50.72 and 50.73 event notifications (i.e., ENS 288696, and LER 95-05) to the NRC. After the successful completion of turbine vibration and overspeed testing, the operators synchronized the unit onto the electrical grid on June 8, 1995. The power ascension continued until June 13, 1995 when the reactor reached approximately 90% power.

On June 16, 1995, the operators lowered reactor power to approximately 50% power to facilitate a control rod pattern adjustment and a thermal backwash of the sea water side of the condenser. On June 19, 1995, the reactor reached 100% power. The operators controlled reactor power at essentially 100% during the remainder of this inspection period.

2.0 PLANT OPERATIONS (71707, 40500, 92901, 93702, 60710)

2.1 Plant Operations Review

The inspector observed the safe conduct of plant operations in the following plant areas:

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

Control room instruments were independently observed by NRC inspectors and found to be in correlation amongst channels, properly functioning and in conformance with Technical Specifications. Alarms received in the control room were reviewed and discussed with the operators; operators were found cognizant of control board and plant conditions. Progress was made towards achieving an alarm free main control board. When discussing the status of nuisance alarms with operations section management, the inspector was informed of a new morning update sheet in development that highlights the number of lit alarms, the reason for each alarm and the corrective actions needed to clear the alarmed condition. Control room and shift manning were in accordance with Technical Specification requirements.

During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication of equipment status. These records included various operating logs, turnover sheets, tagout, and lifted lead and jumper logs. Extensive management oversight of outage and power ascension activities was observed during the plant manager's morning meeting, control room tours and plant walkdowns. Additionally, when placing the generator stator cooling system temperature control valve controller into service for a post-modification calibration, a reactor operator alertly noticed that the controller operated in a reverse acting rather than a direct acting manner. Although the maintenance calibration process would have detected and corrected this condition, the inspector noted that the operator exhibited a high level of attention-to-detail to notice the unexpected controller operation.

2.2 Refueling Outage Event Followup

The inspector reviewed two events that occurred near the start of this inspection period to understand their operational significance, evaluate the license response and corrective actions, and determine whether any common causes contributed to the separate events. Both events occurred within a few days of each other with the plant in cold shutdown conditions, nearing the completion of refueling outage (RFO) 10 activities. Operational evolutions during this time frame (May 12-17, 1995) included preparing for a reactor cavity draindown by placing the condensate storage tanks (CST) in a recycle lineup with the condenser hotwell, draining the reactor cavity water to the CST, and placing shutdown cooling in service after isolating the augmented fuel pool cooling mode of operation.

The first event involved chloride intrusion into the hotwell, CST, and reactor cavity as a result of the loss of a plug from a cracked condenser tube. The focus of this event was not the missing plug, which could have been dislodged in several ways; but rather the timeliness of identification of the chloride (i.e., salt water) intrusion into the hotwell. If detected quickly enough, the spread of the chlorides to both the CST and reactor cavity may have been limited. Based upon completion of the condenser work, the condensate system was returned to service, but the need for chemical sampling of the hotwell was neither programmatically required, nor requested by operations. The communications between the chemistry and radwaste technicians, based upon turbine building floor sump samples indicating high chlorides, was not sufficiently clear to cause recognition of a sea water leak in the condenser. Further, the communications between operators and chemistry personnel was lacking an understanding of the need for good hotwell chemistry sample results before and during the operation of the condensate system.

The licensee's critique of this event on May 16, 1995 identified poor communications to be a contributing cause to the spread of the chlorides to the reactor cavity. Because the plant was in cold shutdown, the safety significance was minor as the licensee was able to effect cleanup of the chlorides using the condensate demineralizers. The licensee also implemented specific corrective measures relative to the condenser tube plug problem that was the origin of the chloride intrusion. With respect to additional liaison controls between operations and chemistry personnel, the licensee instituted procedural reviews for the coordination of hotwell sampling with returning the condensate system to service following an outage. Additionally, the lessons learned from this event were scheduled for discussion during the annual requalification training of both the operations and chemistry section personnel. The inspector determined that these licensee activities and planned corrective actions were adequately directed toward the specific problems related to this chloride intrusion event.

As documented in section 3.5 of USNRC, Region I inspection report 50-293/95-03, the lack of detailed communications between chemistry technicians and control room operators in the past has led to problems in the tracking of equipment limiting conditions for operation. In that particular case, no adverse safety consequences resulted as the component was restored to service before the allowable outage time of the Technical Specifications was violated. The chloride intrusion event that was evaluated during this inspection period represents another example of incomplete interdepartmental communications, which resulted in a problem, albeit one with minor safety consequences.

Another event occurred on May 17, 1995, shortly after the reactor cavity was drained. At that time, the shutdown cooling (SDC) mode of the residual heat removal (RHR) system was being re-initiated to cool the reactor core as RFO10 was nearing completion. During RFO10, both the fuel in the reactor vessel and that in the spent fuel pool were being cooled by means of an interconnection between the RHR and fuel pool cooling systems, allowing for augmented fuel pool cooling (AFPC). In the AFPC mode 2 of operation, RHR shutdown cooling is unavailable. Therefore, the licensee implemented a section of an RFO10 temporary procedure (TP95-010, Attachment 4), disconnecting certain interlocks that prevent the start of the RHR pump with the suction valves closed. This was done to allow for parallel work on the RHR suction valves, MO-1001-47 and 50, with AFPC in service. However, when AFPC was taken out of service, TP 95-010 did not require the interlocks to be restored at that time.

Consequently, on May 17, when control room operators started the "B" RHR pump to establish SDC with the MO-1001-47 valve closed, the interlock preventing a pump start was bypassed and the pump ran for a period of time with no suction. This was subsequently followed by a water hammer down the evacuated line when the valve was opened. The closed position of valve MO-1001-47 had been established by the conduct of a instrumentation and control (I&C) test. Restoration of the valve lineup from this test placed valve MO-1001-47 in its normally closed position, rather than in a lineup to support SDC. The specific I&C test procedure (8.M.2-2.10.3-3) indicates as a prerequisite that RHR shutdown cooling must be isolated, which should have provided warning to the operators that a suction path to the RHR pump was not available.

However, the control room operators incorrectly believed that re-establishing SDC could be accomplished in accordance with a section of the RHR procedure 2.2.19 that did not require checking the suction valve lineup before starting the pump. Attachment 7 to the RHR procedure directed the operators to an inappropriate step in the restoration of SDC, compounding the incorrect assumption that the RHR suction valves were open. Because the operators were using the wrong section of RHR procedure 2.2.19 to place SDC in service, a procedural violation relative to the correct positioning of valve MO-1001-47 did occur.

The inspectors assessed the licensee's critique report for this second event and determined that a comprehensive analysis of the sequence of events had been conducted. Licensee corrective measures were implemented both immediately and on a longer term. Immediate actions included an RHR procedure revision, a system walkdown, and restoration of the normal protective interlock logic. Additional reviews were conducted to ensure that other systems or work activities were not affected by similar configuration problems. The longer-term corrective measures that were initiated involved operator training and lessons learned, "B" RHR pump troubleshooting and further surveillance testing, and actions to address better control of component tagout activities. The inspector considered all of these corrective actions to be responsive to the RHR event and to be performed in a timely manner relative to the startup of the plant from RFO10.

The inspectors evaluated this violation in accordance with the NRC staff enforcement policy (60 FR 34381, June 30, 1995), and concluded that effective corrective actions had been implemented in a timely manner. This failure constitutes a violation of minor significance and is being treated as a non-cited violation, consistent with Section IV of the enforcement policy.

Overall, with regard to both the chloride intrusion and improper RHR pump start events, the inspector determined that the licensee corrective actions were both appropriate and properly directed. The inspector reviewed PNPS procedure 1.3.34 on the conduct of operations for specific "maintenance of system configuration and verification requirements." The inspector determined that acceptable guidance on proper configuration controls is available to operations section personnel. However, in both cases involving these two events, as well as the situation discussed above relative to IR 50-293/95-03, the inspector determined that better interdepartmental communications may have prevented the identified problems. All of these situations involve operator interactions with other departments (e.g., chemistry, I&C), which could have been facilitated if the operators on shift had a more detailed understanding of the work activities being performed by their counterparts in the other sections. The inspector discussed with licensee senior plant management personnel the efficacy of improved interdepartmental communications.

2.3 Power Ascension

After completion of RFO10 activities, the inspector observed portions of the power ascension program. Emergent issues prior to start-up, including the scram discharge volume level switch (section 3.1), were properly resolved. The power ascension program schedule allowed ample time to complete the various operational activities and special tests. BECo implemented augmented management oversight during the power ascension. A general assessment requirements sheet was developed for each major activity including management participation in test briefings. The inspector reviewed the completed management observation sheets, which generally contained performance based observations and actions taken to address any opportunities for improvement.

Operators performed generally well during power ascension as evidenced by the excellent command-and-control and experience level exhibited during special tests and routine operational start-up activities, but some human performance problems were noted. Due consideration was given to maintaining the minimum critical power ratio (MCPR) greater than the MCPR operating limit during power increases. The inspector witnessed portions of the following special tests: automatic depressurization system, high pressure core injection (HPCI) and reactor core isolation cooling (RCIC) turbine testing, and the vibration and overspeed testing of the turbine. The turbine test procedure provided detailed guidance when to trip the turbine due to high vibrations. Operators promptly tripped the turbine several times due to excessive vibrations during initial operation of the two, new low pressure turbines. After the turbine was tripped, operators placed the turbine on the jacking gear for four hours before rolling the turbine again. The elevated vibration levels subsided over time as the new low pressure turbines wore in. The inspector determined that special tests were properly controlled.

The inspector observed that the quality of communications between the control room and remote stations varied greatly due to equipment limitations. For example, when talking with the turbine watch, control room operators had to speak very loudly into the phone to be heard on the other end. Although the inspector witnessed no improper action, better communications equipment may reduce the chance of a miscommunication possibly avoiding a consequential event such as a reactor trip. The plant manager acknowledged the inspector's observation and indicated that the need for better communications equipment used between the control room and remote stations in the plant was already being considered.

Two operator performance related issues occurred during the power ascension. The first issue involved a review of completed safety-related system valve line-ups. The inspector identified a few missed supervisory reviews intended for nuclear watch engineers (NWE). Specifically, the final review was not done for Procedure No. 2.2.8, Standby AC Power System, to independently verify the completion of all valve, switch, and breaker configurations. Also, the final NWE review for Procedure 2.2.20, Core Spray, was not done. The inspector reviewed the various attachments of both procedures and determined that although the final reviews were inadvertently missed, all components required to be lined-up for system operability were properly positioned and independently checked. Hence, the missed reviews were not safety significant. The missed reviews were immediately performed. Operations section management initiated a 100% audit of all system line-up procedures. No other discrepancies were identified. The inspectors evaluated these procedural violations in accordance with the NRC staff enforcement policy (60 FR 34381, June 30, 1995), and concluded that effective corrective actions had been implemented in a timely manner and that no safety consequence resulted. These failures constitute a violation of minor significance and is being treated as a non-cited violation consistent with Section IV of the enforcement policy. The inspector notes that BECo self-assessment processes (e.g., augmented management oversight and quality assurance) missed an opportunity to detect the missed NWE reviews of these two safety-related system line-ups. The immediate actions taken addressed the inspector's concern.

A second operator performance related issue involved the unplanned actuations of the drywell-to-torus and torus-to-reactor building vacuum breakers, on June 5, 1995, during testing of the HPCI turbine. The inspector reviewed the details of this event as described in Licensee Event Report (LER) 95-05 and as observed in the control room. Several factors contributed to the vacuum breaker openings including: the differential pressure between the drywell and torus had not yet been established, surveillance testing was in progress that added steam to the torus, conservative settings of the vacuum breakers, and running out of nitrogen supply to complete inerting the torus and drywell. A review of related operational parameters on a plant computer print-out was performed. The inspector determined that the actuations had no safety significance because the vacuum breakers acted as designed, and did not open due to a differential pressure resulting from an accident condition. The inspector concluded that opportunities exist for increased operator awareness (i.e., cause and effect) during start-up conditions when multiple activities occur in parallel that affect drywell and torus pressures.

2.4 Reactivity Management

As a follow-up from the previous resident inspector report (i.e., 50-293/95-09, section 2.3), the inspector reviewed the results of the in-sequence shutdown margin (SDM) demonstration test done on June 3, 1995. Reactor engineers calculated the reactor core shutdown margin was 1.23% delta-K, which was very close to the predicted shutdown margin of 1.19% delta-K, and well within compliance with the technical specification (TS) minimum SDM limit of 0.25% delta-K. During last inspection period, a deviation occurred between the actual and expected SDM values during an adjacent rod SDM demonstration test done on May 8, 1995. Further review by General Electric determined that overly conservative data was used in the SDM expected value calculation for the adjacent rod test. The following factors accounted for the unexpected deviation: control blade depletion, exposure counting differences and cold target "eigenvalue" bias. The inspector concluded that BECo had successfully met the TS requirement to demonstrate that the reactor core SDM is greater than 0.25 delta-k.

A second reactor engineering issue reviewed was the implementation of industry operating experience recommendations concerning the use of a "soft start-up" strategy to mitigate the possibility of a fuel rod leak due to pellet clad interaction (PCI). Although the barrier fuel design is intended to eliminate PCI fuel leaks that have occurred in non-barrier fuel, some recent operating experience at other nuclear facilities suggests that PCI failures can occur in barrier fuel designs when a fuel bundle is shuffled from the core periphery to a control cell location. Extended low power fuel bundle operation in the core periphery allows gradual pellet-to-clad gap closure due to the effects of (1) cladding creepdown and fuel pellet swelling, cracking and outward relocation, and also (2) build-up of cadmium and iodine that tend to embrittle the cladding. These effects tend to slightly increase the likelihood of a fuel rod failure due to PCI when the fuel bundle is subjected to a rapid local power increase when shuffled to a control cell location. Reactor engineers suggested and operations management limited the ramp-up rate to 0.22kw/ft/hr to minimize the possibility of developing a fuel leak. The inspector considered the awareness and adherence to industry operating experience for minimizing PCI fuel rod failures was a licensee strength.

3.0 MAINTENANCE AND SURVEILLANCE (61726, 62703, 71710, 92902)

3.1 Scram Discharge Instrument Volume Level Switch Troubleshooting

The inspector observed portions of troubleshooting performed by instrument and control (I&C) technicians on a scram discharge instrument volume (SDIV) level element. Shortly before start-up from RF010 on June 2, an invalid actuation of SDIV level switch generated a half scram condition. The work was performed under MR 19501820. This SDIV level element is an electrical device with two probes that can sense a change when submerged by water as the SDIV fills. One of the probes has a heater element to create a deviance between the two probes. The output of the two probes is connected to an electrical bridge. The "A" and "B" train level elements physically connect to the SDIV through instrument standpipes connected to the SDIV. After several electrical checks, I&C technicians determined that heater no. 1 in level element 302-83B appeared degraded. I&C technicians wired spare heater no. 2 on the level element into service. The inspector witnessed the I&C division manger at the work site providing oversight and guidance to the technicians. A written troubleshooting plan was used. I&C verified proper operation of the level switch per post work test procedure 8M1-20, attachments 1 and 2. MR 1950180 was closed.

A day later, operators observed that RPS channel "B" SDIV level switch actuated providing a half scram signal every ten minutes. Operators wrote work request tag no. 033832 to obtain corrective action. MR 19501843 was generated. I&C personnel inspected the layout of the SDIV and the associated instrument standpipe where LE302-83B is located. Using a surface pyrometer measuring the temperatures downstream of scram outlet valves for control rod drives 22-27 and 50-15, I&C workers determined that water trickling past two scram outlet valves entered the top of the SDIV and into the instrument standpipe across the two probes of LE302-83B. The water trickle caused a false actuation of LE302-83B since the SDIV was actually empty. Mechanical maintenance made stem adjustments to the two leaking scram outlet valves. After successful completion of the post work test, MR 19501843 was closed. Although the root cause of spurious actuation was not identified the first time, the inspector concluded that I&C workers used a methodical process to identify and correct the root cause, which was not readily evident.

3.2 Reactor Vessel Leak Check Surveillance

During deep back shift inspection, the inspector witnessed portions of the reactor vessel leak check done in accordance with Procedure no. 2.1.8.5, Reactor Vessel Pressurization And Temperature Control For Class 1 System

Leakage Test. After reaching a test pressure of 1035 to 1070 psig, the licensee did a VT-2 visual examination of the reactor coolant pressure boundary. No unsatisfactory results (i.e., piping or weld through wall leakage) were identified. Control rod scram time testing was performed for the control rod drives replaced during RFO10. Several mechanical joints exhibited leakage. Adjustment of valve packing remedied several valve packing leaks. Valve AO-203-2D, the "D" outboard main steam isolation valve, exhibited gross body-to-bonnet leakage. After depressurizing the test area, the AO-203-2D body-to-bonnet were fasteners torqued, and the test area repressurized. The AO-203-2D body-to-bonnet joint still leaked. Operators depressurized the test area, completing the vessel leak check.

BECo elected to replace the body-to-bonnet gasket on AO-203-2D. The post work test included a visual inspection at normal operating pressure during power operation. During the vessel leak check, the inspector observed excellent coordination between operations, maintenance, engineering and outage management. Plant management participated in the evaluation of test data and also in the decision to depressurize, tighten the AO-203-2D mechanical joint and repressurize. The inspector concluded that BECo performed the vessel leak check and evaluated the test results in a controlled manner indicative of excellent performance.

3.3 Work Request Tagging

The inspector conducted an inspection in the reactor building, randomly checking the status of work request tags (WRT). An equipment concern at Pilgrim is normally identified in the field with a WRT, which has a serialized number matching the problem with the component, system, and, if priority repair is necessary, the maintenance request (MR). In accordance with the Pilgrim procedural requirements, the WRTs should be cleared by operations personnel at the completion of the required repairs.

During the inspection tour, the inspector observed six WRTs with originating dates of 1993 or earlier. The maintenance records were reviewed to determine the status of the proposed work. The licensee was able to provide traceable records for five of the six identified WRTs. In three cases, the required work activities had been completed; in two cases, the need for repair was deemed unnecessary and the work request had been rejected; and in the last case, where no record existed, it was determined that the WRT had been inappropriately hung because the work had never been authorized.

While no uncorrected equipment problems were identified as a result of the WRT followup, the existence of six invalid field tags represents somewhat of a concern from the standpoint of both equipment status markings and the effective completion of the work control paperwork. The inspector reviewed PNPS procedure 1.5.20 regarding the work control process and found no provisions for coordinating the clearance of the WRTs with the completion of the work and closure of the MR packages. Discussions with plant management and maintenance section personnel confirmed licensee cognizance of the need to better control the tagging removal process to ensure that invalid WRTs are cleared from the field.

The licensee work control process has been recently revised since the end of RFO10 and is currently in transition. The inspector determined that the licensee is still evaluating the best method for programmatically handling the accountability and retrievability of WRTs. The inspector also verified that for all six WRT problems identified, the licensee took the appropriate action to clear the tags from the field. The inspector concluded that no adverse safety consequences arose as a result of these WRTs not having been cleared earlier. The licensee management agreed that this area merited further attention and that improvement in the tagging process can be better integrated into the newly instituted work control process at Pilgrim Station.

3.4 Maintenance Performance Indicators

The inspector reviewed with the maintenance section manager the performance indicators referenced by BECo in response to a notice of violation (EA95-10) that involved the failure to reinstall a plug into the port of a drywell-to-torus differential pressure transmitter. The details of this issue are described in NRC Inspection Report 50-293/94-26. One of the corrective action steps to avoid future violations referenced a matrix monitoring system designed to monitor performance of maintenance section craftsmen and supervisors. The inspector reviewed the matrix monitoring system. The completeness of surveillance documentation filled out by maintenance workers and reviewed by supervisors is tracked on the matrix including 12 elements such as missed initials, missing test equipment information, and outside acceptance criteria. During this inspection, matrix information was only available for the electrical section, and not the mechanical and I&C sections. Based on reviewing the electrical section surveillance test matrix, the inspector judged the process was innovative and provided meaningful information. For example, the matrix showed one supervisor who made several performance errors in the area of documentation of surveillance results. The maintenance section manager indicated that corrective action has been initiated relative to the supervisor.

The monitoring matrix information is largely based on documentation reviews of completed surveillance test procedures. The maintenance section manager indicated that the integration of performance-based observations such as quality control findings, management and supervisory oversight observations at the work site and training is under evaluation. Also, consideration is being given to recognize positive maintenance worker and supervisor performance to provide a balance. The inspector determined that maintenance management developed an innovative tool for tracking individual performance. Opportunities exist to incorporate performance-based criteria including field observations and work effectiveness to better diagnose individual worker performance.

Additionally, the inspector reviewed the maintenance section performance indicators that are also referenced as another corrective step to avoid future violations. The indicators include: overtime, work-it-now (WIN) efficiency, open problem reports, and maintenance request trends. The trends of these parameters provided good information but did not address more qualitative measures such as maintenance rework. During RFO10, the inspector noted several failed post work tests and other conditions that resulted in maintenance rework. Some examples included: replacement of the control rod drive common miniflow isolation valve, source and intermediate range monitor drive cable connectors, and incorrect packing installed with the four new motor-operated valves. All deficient conditions were corrected. Maintenance rework, due to a failed post work test or other deficient condition, provides a valuable measure of maintenance effectiveness. Another example of maintenance rework involving an emergency diesel generator is documented in section 3.2.2 of NRC Inspection Report 50-293/94-18. The maintenance section manager indicated that the threshold for reporting maintenance rework is too high. The inspector considers this to be a weakness in the current maintenance program for evaluating work performance. As a result, the trending and analysis of post work test failures and other conditions are minimal. The maintenance section manager acknowledged the inspector's observation and indicated that opportunities for improvement exist in the area of maintenance rework.

4.0 ENGINEERING (37551, 71707, 92903)

The engineering department involvement in plant activities was clearly evident. The evaluation of an alarmed condition in the control room, vessel flange leakage detection, was evaluated and cleared in a safe and expeditious manner. Engineering personnel determined that the alarm resulted from residual water left in the leak detection lines after reactor vessel assembly. Engineering involvement was also evident during the evaluation of the dynamic testing of motor operated valve 1301-61, RCIC turbine steam supply valve. BECo issued LER 95-06, dated July 13, 1995 to document the anomalous results of this dynamic testing. Attendance and active participation by the mechanical, electrical and I&C engineering division mangers at the plant managers morning meeting were evidence of strong licensee management attention and involvement. Overall, the inspector observed active engineering department involvement in the evaluation of operational issues.

4.1 Foreign Material Exclusion

The inspector reviewed the implementation of the programmatic controls for foreign material exclusion (FME) through observations made during RFO10, search of the problem report system and review of applicable station procedures. Two station procedures exist to implement the FME controls. Procedure No. 1.4.35, Personnel And Material Controls, provides guidelines for work activities to maintain cleanliness of systems and equipment and not degrade the system capability to perform the intended function. Temporary Procedure No. 2.1.36, Object Retrieval From Reactor Cavity And Spent Fuel Pool, provides controls for an object to be retrieved from the reactor pressure vessel (RPV), cavity, or spent fuel pool. This procedure specifies that a problem report (PR) should be written for any foreign object observed or dropped into the cavity to prevent recurrence. In response to an object falling into the cavity, the procedure specifies that: (1) stop the evolution (2) assess conditions (3) assess whether or not retrieval can be deferred (4) remove the object or have General Electric complete a lost parts analysis. The inspector determined that adequate foreign material exclusion program controls exist.

The inspector periodically verified the accuracy of the loose parts log maintained on the refueling floor. A computer search of RFO10 PRs, using a key word of "loose parts", identified a few instances where the refueling crew found loose parts or debris in the vessel or where loose parts fell into the vessel or cavity. For example, the identification of existing loose parts included PR 95.0232, which documented a cotter pin found in the core. The cotter pin was retrieved. An example where a loose part fell into the core or cavity was PR 95.0342. A 1/2 inch drive, 15/16 inch socket, and a 1/2 inch to 3/8 inch drive adapter, held together by duct tape inadvertently fell into the cavity or core during RFO10. The inspector discussed this event with the RFO10 outage manager. In accordance with procedure 2.1.36, BECo initiated a PR, searched for the lost pieces (which was unsuccessful), and ultimately contracted General Electric to conduct a lost parts analysis. The evaluation of the PR, to identify and implement corrective actions to prevent recurrence, was still in progress at the end of this inspection period.

By letter dated May 22, 1995, General Electric concluded that safe operation is not compromised by the presence of the socket, adapter and tape inside of the reactor vessel. The only possible concern could be fretting wear which would be detected by abnormal offgas system parameters. The inspector identified no concerns with the evaluation, but did note overall that the inability to retrieve the lost pieces had some impact that required further analysis. The inspector concluded that BECo adequately followed the FME program controls to document, search and retrieve lost parts or perform a lost parts analysis. Sufficient preventive measures exist for the control of foreign material in exclusion areas. The inspector had no further questions or concerns pertaining to this matter.

5.0 PLANT SUPPORT (71707, 71750, 92904)

5.1 Emergency Preparedness Combined Function Drill

The inspector witnessed a portion of the planning, performance, and critique of the combined function emergency planning (EP) drill (95-04) conducted on June 29, 1995. This ungraded drill was developed by the licensee's EP staff and intended to test the Emergency Response Organization (ERO's) ability to assess, identify, classify, and respond to emergency conditions and take the appropriate protective actions. The drill was announced as a training exercise, allowing for controller interaction with the licensee's drill participants for the purpose of providing instruction and facilitating the lessons learned from the evolving scenario in a real-time setting.

The inspector observed the controller briefing on June 28, 1995 and reviewed the drill scenario, sequence of events, and timeline. The inspector noted that the exercise was developed in such a way leading to release rates that would necessitate escalation to an emergency action level (EAL) of Site Area Emergency, but not beyond. The sequence of events included in the drill were projected to cause EAL escalation and entry into certain emergency operating procedures (EOP) based upon assumed station response to the simulated equipment failures and plant transient conditions. The inspector determined that the drill narrative and controller briefing were both well planned to support conduct of this exercise in a way that supported the training objectives.

The inspector witnessed the conduct of the drill at the emergency operations facility (EOF), the technical support center (TSC), and the operations support center (OSC). Good command and control of their respective emergency facilities by the Emergency Director and the Emergency Plant Manager were in evidence. The inspector observed the drill controllers effectively interfacing with the players by questioning the rationale behind certain plant decisions and by prompting additional considerations for licensee player action where appropriate. The exercise timeline was generally followed with the emergency facility manning and activation and EAL declarations in accordance with established guidelines. The inspector periodically checked the availability of current information on the status display boards in both the TSC and EOF to verify not only the correct interpretation of simulated plant conditions, but also the proper exchange of emerging event information. The inspector witnessed the termination of the drill and the subsequent conduct of a self-assessment of performance in the TSC/OSC facility immediately thereafter.

On June 30, 1995, the inspector attended an EP drill critique with comments provided by the lead controllers in the EOF, TSC, OSC, media center, and corporate information center. Areas for improvement, both in the drill conduct and in the ERO's performance, were discussed. The inspector observed a good, critical self-assessment of performance and the identification of future training needs. The inspector noted that controller comments were sufficiently detailed to promote adequate evaluation and response by the licensee's EP staff.

Overall, the inspector determined that the scope of the combined function drill adequately tested the licensee's ERO in the areas where specific performance objectives had been developed. Also, as a training vehicle, the conduct of the drill successfully exercised the functions of participating staff. The inspector concluded that the licensee exhibited a critical self-assessment capability and not only demonstrated ERO performance at an adequate level, but also identified areas for further improvement in the EP program and its implementation.

5.2 Radiological Controls

During tours of the radiological controlled area (RCA), the inspector verified that high radiation and contaminated areas were properly posted with radiological warning signs. During routine inspection tours of the plant, the inspectors checked for worker compliance with the requirements of radiation work permits and the appropriate use of personnel monitoring devices. Also, the use and control of contaminated tools within the RCA was monitored to assess the progress made to address the issues discussed in section 5.2.2 of NRC Inspection Report 50-293/95-09. Little progress was made during this inspection period. The inspector observed that wrenches used by operators to change the control rod drive system filters were not marked with magenta paint. The magenta paint identifies the tools as potentially contaminated.

Further, tools contained in two operations section tool boxes, located in the reactor building, were not marked.

The inspector noted that the management expectation to mark all tools, used on potentially contaminated equipment, was more restrictive than specified in procedures 1.3.114, Conduct of Radiological Operations, and procedure 6.1-213, Radiological Controls Of Vehicles and Materials. These procedures specify that portable tools with fixed contamination greater than 100 counts/minute above background will be labeled with magenta paint. In order to clarify its position on the use of tools in contaminated areas and to provide consistent expectations in this regard for all station workers, the licensee initiated a procedure change with respect to the radiological control of tools.

The plant manager showed the inspector new tool boxes installed at each level of the reactor building to store operations and maintenance tools. Also, the radiological section manager provided a consolidated list of short and long term actions with scheduled completion dates intended to improve contaminated tool control and labeling.

5.3 (Open) Inspector Follow Item (50-293/95-13-01): Plant Housekeeping and Scaffolding

The inspector monitored the progress made by BECo in plant clean-up following the completion of RFO10. The appearance of the turbine generator and feed pump level of the turbine building was greatly enhanced being newly painted. Cleaning and preservation coating of the screenhouse, along with the repair of minor equipment deficiencies, began during this inspection period. The upgrade of the screenhouse material condition is part of a four year plant material condition upgrade process that began in 1995. The upgrade of the reactor building, including the quadrant rooms, is scheduled for later in the 1997 and 1998 time period. The commitment of resources to implement an extensive plant material condition upgrade process is significant.

The inspector conducted tours of the intake structure, including those areas housing the salt service water (SSW) equipment, the fire pumps, traveling screens, and screenwash pumps. Maintenance activities were in progress to replace a section of hypochlorite piping. The inspector interviewed the technician performing the piping repairs to determine the scope of the replacement activities and adequacy of the work controls. Painting and coating upgrade activities were also in progress throughout the intake structure. Due to the harsh salt water/spray environment, restoration of the surface condition of components and other material located in this building is an effort requiring periodic evaluation and work planning of a repetitive nature. The inspector examined a schedule for the upgrade and improvement activities, which coordinated the scope of repairs with component replacements, modifications, and general area restoration activities.

The inspector interviewed both the SSW system engineer and the licensee supervisor of the upgrade project. The scope of work for the various areas within the intake structure has been planned and is being controlled by maintenance requests documenting detailed repair or rework activities. While certain decisions on material replacement have not been finalized, the inspector determined that some design changes are also being evaluated which would attempt to minimize the adverse impact of the harsh, salt-spray environment. The inspector observed precautions being taken to assess the impact of and coordinate ongoing activities so as to properly address equipment operability and personnel safety concerns related to some latent work effects (e.g., paint fumes).

The material upgrade activities in progress and planned in the intake structure appear to be well controlled. Licensee attention to this area of plant improvement is a positive initiative and well justified in attempting to prevent component degradation to the point where operational problems might develop. The inspector determined that licensee management support of this project, as well as other SSW/screenwash betterment activities, is appropriately directed toward assuring equipment maintenance and overall safe and reliable plant operations.

However, several plant areas were not cleaned up yet following RFO10 including the refueling floor and the "A" residual heat removal (RHR) valve room. The inspector observed dirt, a large lagging pad removed from an RHR pine and a set of wet coveralls laying in the contaminated area of the "A" RHR valve room. Also, a set of coveralls was left on the top of the east hydraulic control unit (HCU) bank. The east and west hydraulic control unit banks remained contaminated. An unused temporary electric power supply panel and radiological stanchion remained adjacent to the east HCU bank. The inspector did note progress was made during this period in decontamination of the reactor core isolation cooling turbine room such that anti-contamination clothing is not required for general access. Opportunities exist to further clean plant areas following RFO10.

Two longer term plant material conditions were observed by the inspector. First, the lower portions of the "A" and "B" quadrant rooms remain as high radiation and contaminated areas. These conditions do not allow plant workers, and managers on tours, easy and full access to these areas. Plant management acknowledged that the "A" and "B" quadrant room radiological access conditions are restrictive. A limited, short term decontamination effort is planned to improve access into these areas. In the longer term, the quadrant rooms are scheduled for decontamination and coating with preservation paint as the last part of the material plant condition upgrade process.

A second long term issue involves the scaffold structures erected adjacent to safety-related equipment in the "A" RHR quadrant. BECo made the decision to leave the scaffolding erected for work efficiency and to minimize dose required to remove, and then re-install at a later time. The inspector noted another set of scaffolding left erected and not used on the 51 foot elevation of the reactor building. The scaffold is erected above the primary sample sink and a safety-related instrument rack. The potential interaction of these two scaffolds with safety related equipment during a seismic event, as well as the degraded housekeeping observed in the plant will be further reviewed. **(IFI 50-293/95-13-01)**.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (40500, 71707)

6.1 Licensee Event Report Review

The inspectors reviewed one Licensee Event Report (LER) submitted to the NRC to verify accuracy, description of cause, previous similar occurrences, and effectiveness of corrective actions. The inspectors considered the need for further information, possible generic implications, and whether the event warranted further onsite followup. The LER was also reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREC 1022 and its supplements.

- **LER 95-05**

LER 95-05, Drywell-to-Torus Vacuum Relief System and Torus-to-Reactor Building Vacuum Relief System Actuations, dated July 14, 1995, describes unplanned actuations that occurred during start-up from RFO10. Details of this are documented in section 2.3 of this report. No violation of regulatory requirements was identified. The LER provided an excellent description, cause and corrective actions developed for the event. While several factors contributed to these actuations, as discussed in section 2.3, the root cause of both events relates to the lack of establishing the differential pressure requirements between the drywell and torus appropriate to the plant conditions and operational evolutions at that time. The inspector had no further questions regarding this event.

6.2 Management Effectiveness

Management oversight of RFO10 completion and power ascension to 100% reactor power contributed to safe plant operation. The power ascension schedule provided ample time to complete operational activities. A strong safety focus was evident during special tests such as the reactor vessel leak check and the turbine vibration and overspeed testing. In both cases, the inspector witnessed plant management presence in the control room and during the evaluation of test data. The turbine overspeed test procedure provided specific abort criteria when to the trip the turbine due to abnormal vibrations, which incorporated lessons learned at other nuclear facilities. The chemistry effects of the new low pressure turbines were anticipated and understood. Likewise, the application of industry experience involving reactivity management for a "soft start-up" mitigated the potential for PCI fuel rod failure. In the aggregate, these positive actions, including the awareness and application of industry experience, enhanced nuclear safety at the Pilgrim site.

Following completion of RFO10, BECo initiated or continued with the implementation of several major performance and plant upgrade initiatives. New streamlined work control and planning systems have been implemented. The effectiveness of these changes cannot be measured yet. Also, a four year program to improve the plant material condition represents a significant effort to upgrade plant areas and lower the amount of operator work arounds.

Two self-disclosing, operational events occurred at the end of the outage (i.e., chloride intrusion event, RHR pump run with suction valve shut) that the inspector analyzed. It was determined that communications between departments is an area of opportunity for improvement. The plant manager also recognized this and has plans to emphasize the need for effective communications. Also, the inspectors found three minor problems in the implementation of station programs including clearance of work request tags, missed valve line-up reviews on two safety-related systems, and in the area of contaminated tool control. These three examples represent potential weaknesses in the implementation of plant programs. Lastly, maintenance section management has made progress in area of individual and program level performance indicators. The absence or lack of a qualitative maintenance indicator such as maintenance rework, including the post work test success rate, was discussed with licensee management personnel with regard to recently implemented (e.g., work controls) and other planned changes to the maintenance program.

7.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (71707)

7.1 Routine Meetings

Two resident inspectors were assigned to the Pilgrim Nuclear Power Station throughout the period. Back shift inspections were performed on June 21 and 22, and deep back shift inspections on May 29. On June 20 and 21, 1995, Mr. Richard Conte, the NRC Region I Section Chief assigned to Pilgrim, visited the site for normal oversight duties. Additionally, Mr. Conte held discussions with section and executive level BECo managers to discuss the results of the executive plant performance review (EPPR).

Throughout the inspection, the resident inspectors held periodic meetings and toured portions of the plant with plant management to discuss inspection findings. On July 12, 1995, the inspector held an exit meeting to present the findings and assessments to plant management. No proprietary information was covered within the scope of the inspection. No written material regarding the inspection findings was given to the licensee during this inspection period.

7.2 Other NRC Activities

Mr. Edward King led a routine security inspection from May 15 to May 18, 1995. The results of this inspection are documented in NRC Inspection Report 50-293/95-12. Also, Mr. James Trapp conducted an engineering inspection the week of June 19, 1995. The results of this inspection are documented in NRC Inspection Report 50-293/95-14.