U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.: 50-293

Report No.: 95-22

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

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: October 8, 1995 through November 18, 1995

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Scope: Resident Inspector safety inspections were conducted in the areas of plant operations, maintenance and surveillance, engineering, and plant support. Reactive inspections were conducted for the actuation of two emergency diesel generator fire suppression systems, the November 14 coastal storm preparations, and a detailed follow-up inspection on the issue of elevated salt service water inlet temperatures. An inspection of the vendor manual update program status was conducted.

Findings: Performance during this six week period is summarized in the Executive Summary. No violations were cited. An unresolved item concerning elevated salt service water inlet temperatures was updated (50-293/95-21-03, Section 4.0). An unresolved item concerning overall maintenance performance was closed based on improving performance (50-293/95-18-03, Section 3.3). A backlog of vendor manual updates was dispositioned as a noncited violation based on low safety significance, self-identification and apparent corrective actions but the effective resolution of this issue will be further reviewed as an unresolved item pending completion of BECo actions (50-293/95-22-01, Section 4.3). An inspector follow item was identified concerning the engineering control of vendor services (IFI 50-293/95-22-02, Engineering Report Details, Section 2.).

EXECUTIVE SUMMARY

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Plant Operations: Operators performed well during planned and emergent operational activities. For example, operators methodically lowered power to 15% to facilitate planned maintenance. The plant management decision to lower reactor power, to be within the condenser bypass capability, was based on avoiding a reactor scram if an inadvertent turbine trip occurred. This reflected an strong safety focus. After corrective maintenance of two nonsafety related high risk activities, operators returned the unit to full power. Also, operators responded effectively during an unrelated operational event when the main condenser vapor valves unexpectedly closed due to an equipment malfunction. Prompt and effective operator actions, using abnormal operating procedure guidance, averted a possible reactor scram. Lastly, thorough preparations for adverse weather conditions was observed.

An alarm free (blackboard) main control board was established for the first time as an initiative to improve the control room environment and re-enforce high operator standards. One annunciator for fire water storage tank level on panel C7 remained in alarm and continued to be evaluated by engineering and maintenance for corrective action. Two unplanned actuations of the "A" emergency diesel generator fire suppression systems occurred due to electrical board malfunctions. A thorough root cause analysis was conducted to develop appropriate corrective actions. A nonlicensed, radwaste operator (and potential others) was observed accepting the existence of an equipment problem that resulted in a "workaround" condition. This area was weak due to the lack of follow-up actions by the radwaste operator and lack of procedural guidance on compensatory measures log.

Maintenance and Surveillance: Instrument and controls technicians completed surveillance activities in a competent and professional manner using proper self checking and procedural adherence techniques. A procedure clarity problem was properly addressed by an I&C technician. Instrumentation upgrades and modifications made in the screen house were properly controlled including coordination of underwater work and configuration of the sluice gates. Based on a general overall improving trend of maintenance performance as a result of the maintenance improvement plan, a past unresolved item concerning deficient maintenance performance was closed. Positive effects, including a decreasing trend in the maintenance request running repair backlog and increased use of performance indicators, were observed from work planning and scheduling improvements and increased worker attention-to-detail. Troubleshooting on the EDG fire sprinkler actuation was hindered by the lack of comprehensive system drawing and updated vendor information (Resident Report Section 2.2).

Engineering: Concerns were identified for the evaluation and corrective actions associated with elevated salt service water (SSW) inlet temperatures. A 10 CFR 50.59 safety evaluation to determine whether or not an unreviewed safety question existed as a result of elevated SSW inlet temperatures had not been completed. The adequacy of BECo's actions is being evaluated by the Office of Nuclear Reactor Regulation (NRR). Several informal, interim actions including the adequacy of procedure changes, memorandums and operations standing orders reflected poorly on BECo's ability to provide the operators with clear guidance on SSW inlet temperature limits and to adhere to existing administrative control. A review of the Pilgrim operating experience identified earlier opportunities to properly evaluate the effects of elevated SSW inlet temperatures. Although draft information from the design report identifies 75 degrees Fahrenheit as an acceptable SSW inlet temperature limit, the aforementioned concerns have potential regulatory significance.

Loose nuts were identified on the emergency diesel generator foundation anchor bolts. Although an immediate operability concern did not exist, NRC identification of this deficiency represents a weakness since neither the respective system engineer nor mechanical maintenance workers identified the deficiency. Lastly, a backlog of safety related vendor manual updates reflected weakness in program management and coordination albeit the backlog having been previously recognized and acted upon by BECo.

Plant design changes continue to represent engineering efforts of high technical quality and with sound safety bases. Where corrective actions are required to address design or analytical problems that originate with vendor activities, the licensee oversight of root cause analyses and measures taken to prevent problem recurrence could be enhanced. Currently, the effectiveness of such controls relies more on individual initiatives than programmatic direction. In the area of engineering initiatives, management goals, priorities, and resource allocations are well directed and have been balanced with competing (e.g., reorganization) objectives.

Plant Support: An opportunity for improvement was observed during a practice emergency preparedness drill involving core damage assessment. Actions taken to protect the public and environment were clearly evident. However, the core damage assessment group debated the applicability of a core damage assessment graph that resulted in not providing any input to the emergency plan manager before the drill scenario conditions worsened to the next plateau. Inspection followup occurred in report No. 50-293/95-25.

Positive performance was evident in the radiological control functional area. The ALARA committee is establishing challenging but achievable department goals for 1996. Progress was made in cleaning contaminated areas to reduce the overall percentage of contaminated plant areas. For example, the fuel pool cooling filter room was "deposted" as a contaminated area allowing easier personnel access.

The fire protection program and procedures were appropriately established and implemented to meet NRC requirements. Good program performance was attributed to the knowledge of the fire protection and training staff. The clarity and effectiveness of certain administrative control requirements were questioned for minor deficiencies identified, including the storage of combustibles, housekeeping inspections, hot work area preparation, and compensatory measures when emergency lights are removed from service. No safety concerns were found. During a drill the fire brigade was observed to be well organized and knowledgeable of the proper fire fighting techniques. Completed quality assurance audit inspection scopes were good and appropriately verified quality assurance and fire program attributes. In the area of fire protection management oversight, performance indicators appear to be narrowly focused with no trending measures.

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1.0 SUMMARY OF FACILITY ACTIVITIES

At the start of the report period, Pilgrim Nuclear Power Station was operating at approximately 100% of rated power. On October 13, power was reduced to approximately 15 percent to backwash the main condenser and perform scheduled maintenance activities. Power was returned to approximately 100 percent on October 15. On October 17, operators lowered reactor power to 60 percent for a control rod pattern change. On October 18, operators increased reactor power to 100 percent where the reactor operated during the remainder of the report period.

2.0 PLANT OPERATIONS (71707, 92901, 93702)

2.1 Plant Operations Review

The inspector observed the safe conduct of plant operations, during regular and back shift hours, in the following 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 the inspector and found to be in correlation between channels, properly functioning and in conformance with Technical Specifications (TSs). Operator shift logs, limiting conditions for operation (LCO) log, and night orders were routinely reviewed and found to be appropriately maintained to reflect plant conditions and communicate plant activities. Alarms received in the control room were reviewed and discussed with the operators who were aware the alarms were in and cognizant of the cause. Control room and shift manning were in accordance with TS 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.

During the planned October 14, 1995 downpower to approximately 15% power (discussed further in Section 2.3) and subsequent return to full power operations, operators competently completed all activities with no human performance errors. The inspector noted that low power operations in a boiling water reactor, such as Pilgrim, requires increased operator attention to avoid operational transients. Later in the period, operators promptly and effectively responded to an equipment failure that had the potential to cause a plant scram. Specifically, on October 17, 1995, the main condenser vapor valves went closed unexpectedly. Operators followed the abnormal procedures for manually bypassing the steam jet pressure control valves and the offgas low flow vapor valve closure. After the main condenser vapor valves opened, main condenser parameters returned to normal. Operations management convened a lessons learned meeting to further review the event. The root cause of the valve closure was a pressure regulator malfunction. Operators performed well during planned and reactive operational challenges.

As a direct result of a BECo initiative to establish an alarm free main control room, BECo established a "blackboard" on the front panels in the control room. Using a blackboard concept promotes prompt identification and alarm response actions. One remaining annunciator remained on a back control panel (C7), for water level in the fire water storage tank. At the end of the inspection period engineering and maintenance personnel continued to investigate the cause of this alarm. The inspector determined that the establishment of a blackboard on the front control room panels for the first time directly enhanced the control room environment to allow operators to focus on emergent plant off-normal conditions.

2.2 Unplanned Actuation of the "A" EDG Pre-action and Dry Chemical Fire Suppression Systems

On October 11, 1995, while restoring power to the alarm panel for the sprinklers for the "A" emergency diesel generator (EDG), several alarm and trouble conditions were received and cleared within minutes. The alarm panel was tagged out of service for work on the respective EDG starting air tank. While the trouble lights on the alarm panel are expected when restoring AC or DC power sources, the alarm lights on the same panel are not. These trouble lights have occurred before at Pilgrim and usually clear once AC power is restored. Approximately one hour later, the nuclear watch engineer (NWE) noted that the drain valve for the system deluge valve was spraying water onto the EDG air compressors and floor. While isolating the drain valve, the heads for the floor system activated, spraying water onto the floor of the "A" EDG room. The NWE observed that the sprinklers on one side of the diesel were spraying. He did not observe whether the other side or middle banks actuated. This event was documented in Problem Report (PR) 95.9534. The sprinkler system was reset and left in-service. After it was reset, no further alarms were received and the system was declared operable. Preliminarily, personnel error during the detagging of the system was thought by BECo to be the cause of the deluge valve actuation. The NWE examined the diesel for operability concerns and found none. Therefore, the diesel also remained operable.

The sprinkler systems for the EDGs are "pre-action" systems. Normally, the piping from the sprinkler heads to the deluge valve is dry. There are two elevations to the EDG sprinkler system. Each elevation requires the deluge valve to actuate to fill the piping up to the sprinkler heads. The ceiling elevation sprays from the ceiling above the diesel and requires thermal detectors to actuate and open the sprinkler heads. These sprinklers did not actuate during the event. The floor elevation sprinklers are initiated by infrared detectors. These sprinklers are in banks, one on each side of the EDG and one underneath. Per design, the banks are actuated by solenoid valves allowing the sprinklers to spray water. Whenever one side bank is actuated, the middle is also designed to actuate. The floor sprinklers sprayed water during this event.

The inspector walked down the affected diesel and noted that the sprinkler heads on either side of the diesel were aimed to only spray the side of the machine and not impact any electrical components. Most of the sprinklers beneath the diesel spray into a void and were not of concern either. However, there was one spray nozzle which was located between the engine and generator.

The inspector questioned whether water could enter vents on the generator housing and possibly affect operability. The civil/mechanical engineering manager walked down the diesel and found no operability issues. A formal operability evaluation eventually documented this assessment. The inspector discussed this issue with BECo representatives and agreed that the direct impingement of water representative on the generator from this nozzle was unlikely and that the mist that may enter the area would likely dry quickly. As a conservative measure, to eliminate any potential for water from the sprinkler inadvertently interacting with the generator, BECo removed the subject spray nozzle from both EDGs.

The inspector reviewed the design basis for the EDG pre-action sprinkler systems to evaluate the acceptability of the sprinkler head removal. The inspector verified that only the ceiling elevation sprinkler system is required to comply with NRC fire protection requirements and is Final Safety Analysis Report (FSAR) fire protection safety-related or "Q". This system prevents a fire on one EDG from affecting the other EDG. However, the floor elevation system is not fire protection "Q" and was installed to protect BECo's economic investment in the EDGs. Therefore, the removal of the subject spray nozzle did not affect the ability of the safety related portion of the system to perform its function.

On October 24, 1995, control room operators noted an intermittent trouble condition on a fire alarm control panel related to the "A" EDG fire area. This condition was documented in PR 95.9556. The inspector verified the TS-required continuous fire watch was established and maintained until the system was restored. The floor elevation sprinkler system partial actuation was composed of two actions. The first was the actuation of the deluge valve, which was originally attributed to the detagging in progress on October 11. However, after the intermittent trouble lights were received on October 24, troubleshooting was initiated. The licensee then determined the root cause to be a faulty electrical board for the floor elevation portion of the system. This analysis was discussed with the vendor who confirmed that the discovered condition would have caused the inadvertent fire suppression spray actuation.

The second action required for the pre-action system initiation was the subsequent actuation of the solenoid valve which allowed the opening of the sprinkler heads. BECo investigation determined that only one of the wall banks initiated. Neither the other wall bank nor the under-generator bank sprayed water. The exact root cause of the solenoid actuation could not be determined. However, BECo postulated that the inadvertent actuation was due to the valve seating surfaces becoming obstructed with foreign material. Therefore, when the pressure from the water admitted by the deluge valve was sensed, the valve eventually opened. The system was tested in accordance with its surveillance procedure and found to be operable. Recommendations were made, and are being tracked by BECo, to disassemble and clean the solenoid valves and their strainer on a periodic basis to preclude recurrence. The inspector discussed this condition with BECo representatives and verified that this condition would not prevent the solenoids from properly operating if a valid initiation signal is received. Therefore, the licensee's decision not to immediately inspect these valves was not a concern.

The inspector reviewed the troubleshooting activities, discussed the root cause evaluations for both the deluge valve and solenoid valve actuation, and reviewed the corrective actions with the cognizant personnel. The inspector determined that BECo's limited investigation into the cause of the deluge valve actuation prior to October 24th was reasonable considering the past history of this system. The subsequent troubleshooting was thorough and post-work testing appropriate to restore the system. The inspector considered the interaction with the fire system equipment vendor was positive. The inspector did note that licensee personnel had a difficult time in troubleshooting this event due to the lack of comprehensive drawings and vendor information for the system. Some of the vendor manuals were not updated (Section 4.3, also) and a comprehensive drawing of the system did not exist. The licensee initiated actions to resolve these problems.

In a related event on October 13, two days after the pre-action sprinkler initiation, the dry chemical suppression system released in the "A" EDG room. This actuation was documented in PR 95.9536. This system is located under floor plates in the diesel generator room. It's function is to protect the diesel from fire resulting from a fuel leak in lines located in a trench beneath each EDG. This trench and the detector were filled with water, leading to the actuation of the system. Subsequent evaluation determined that the detector needed to be replaced due to being wetted by the October 11, spray actuation. At the end of the report period, the dry chemical cylinders had been recharged and options for the replacement of the detector were being investigated. The inspector verified that the required hourly fire watches were in place and understood their responsibilities. At the close of the inspection period, the system was not returned to service and the fire watch remained.

The inspector concluded that no human performance issues were involved with the inadvertent fire suppression system actuation, which resulted from an electrical board malfunction. The subsequent dry chemical suppression system actuation occurred as a result of the water suppression system actuation. BECo's root cause evaluation was reasonably thorough. The proper compensatory fire watches were implemented to compensate for the inoperable fire suppression systems. The final EDG operability determination subsequent to the October 11, actuation was thorough. However, troubleshooting on the EDG sprinkler actuation was hindered by a lack of comprehensive system drawings and updated vendor information (Section 4.3, also).

2.3 Corrective Maintenance Downpower

Plant management scheduled and implemented a significant power reduction to approximately 15% on October 13, 1995 to facilitate a planned maintenance period for two nonsafety-related equipment repairs. The main turbine emergency trip system (ETS) switch and main generator automatic voltage regulator were replaced. Although the associated tagging orders did not require a plant downpower, plant management lowered reactor power to approximately 15% (within the condenser bypass valve capability) so that an inadvertent turbine trip would not cause a reactor scram. These maintenance items were high risk activities that involved working on and around energized circuits. Also, due consideration was given to performance of post work testing, which could also initiate a plant transient. The inspector determined that plant management demonstrated strong safety perspective by lowering power to 15% to avoid the possibility of an inadvertent scram during trip critical maintenance repairs.

2.4 Operator Compensatory Measures Noted During RWCU Filter Operations

During a routine tour of the reactor building on November 13, the inspector observed portions of a reactor water cleanup (RWCU) filter backwash and precoat. An operator was using procedure 2.2.83, Reactor Cleanup System. The RWCU system is non-safety related, with the exception of the containment isolation valves. The evolution was performed by a radwaste-qualified, non-licensed operator. The operator was knowledgeable of the system and the procedure. During the operation, the RWCU filter demineralizer backwash and fill valve, AO-1279-111, did not operate as expected per the procedure. To compensate for this condition, the operator ported air off of the valve solenoid which enabled the valve to move. The inspector noted that no work request or caution tags were attached to the affected equipment. Also, the operator indicated that he had performed this procedure before and that the actions taken to port the air were usually needed to operate the valve.

The inspector informed the NWE who indicated that the operator's actions were not consistent with management expectations for initiating work requests to address equipment problems. The inspector verified that the appropriate work request tags and maintenance requests were subsequently issued for the valve in accordance with procedure 1.5.20, Work Control Process. In addition, the inspector noted that caution tags were hung on the equipment to alert plant personnel to problems encountered with the system and to direct acceptable operator action.

The caution tag on the valve directs plant personnel to perform the same actions taken by the radwaste operator. However, the inspector considered the lack of action to previously address the equipment failure was a weakness. Essentially, the radwaste operator (and potential others) accepted a "workaround" condition. The inspector reviewed the operator compensatory measures log and noted this condition was not listed. According to Procedure 1.5.20, an operator "workaround" is, "A condition requiring Station employees to operate (or work with) plant equipment (or systems) in a manner other than the original design..." There was no procedural guidance for placing equipment in the compensatory measures log. However, equipment which is listed in the operator compensatory measures log is periodically reviewed to ensure the item is repaired in a timely manner since BECo is striving to reduce the number of operator workarounds in the plant. The inspector discussed this issue with operations personnel who agreed the valve was an operator workaround and the valve was listed in the compensatory measures log.

The inspector concluded this area was weak with respect to radwaste operator actions of accepting a "workaround" condition without initiating corrective actions and to the lack of procedural guidance for the compensatory measures log. No similar observations have been made associated with safety related equipment.

2.5 Coastal Storm Preparations

On November 14 and 15, operators prepared for a coastal storm which was accompanied by heavy rains and sustained winds of 45 mph with gusts up to 60 mph. Storms of this nature could possibly provide challenges at the intake structure and switchyard. When the winds are from north to east, seaweed, which is directed into the intake structure and traveling screens, has the potential to damage screens and to clog the intake bays. These bays feed water to systems used to cool safety-related systems. In addition, salt mist created by the heavy surf has been carried by the wind into the switchyard causing flashovers and plant shutdowns in the past.

The inspector observed the licensee's storm preparations on November 14. Operators were stationed in the screenhouse to turn screens prior to the storm's arrival. The inspector verified procedure 2.1.37, Coastal Storm - Preparation and Actions, was appropriately entered and followed when wind speed rose to between 15 and 25 mph from north to east. The inspector observed good storm preparation in accordance with the procedure which included: securing all outside materials to prevent missile hazards, installing a personnel safety line from a plant building exit to the screenhouse, staging fire hoses to be used as a backup to the installed screenwash systems, continuously rotating screens, and conducting shift briefings on the applicable procedures.

Good synergism was evident between operations, work control, and maintenance for the storm response. The work week manager walked the outside of the plant down with shift management to ensure equipment was secured. It was discovered that the safety bars were missing from the screenhouse. These bars are required to be installed in front of the traveling screens after their covers are removed. Subsequently, maintenance department responded and built staging to perform the function.

The inspector discussed the storm preparations with the control room and screenhouse operators and verified their familiarity with the proper procedures that may have been required during the storm including intake level fouling and intake screen shear pin replacement. The inspector observed strong management oversight and participation in the storm effort in the screenhouse. No operational problems were encountered with the storm. Screens were turned continuously and the intake structure level was not challenged. Salt mist was not carried over into the switchyard. The plant operated at 100 percent of rated power through the storm. After the storm, the operators continuously turned the traveling screens through several tides to ensure no intake fouling occurred.

The inspector concluded that the plant staff responded well to the storm. Cooperation among departments was evident and ensured the plant was prepared for the storm. Operators were cognizant of the storm conditions and followed the appropriate procedures to keep the plant in a safe condition. In addition, management oversight was evident in preparing for and operating during the coastal storm.

3.0 MAINTENANCE AND SURVEILLANCE (61726, 62703)

3.1 Routine Maintenance and Surveillance Observations

The inspector observed portions of selected surveillance and maintenance activities to verify proper calibration of test instrumentation, use of approved procedures, performance of work by qualified personnel, conformance to LCOs, and to verify correct system restoration following maintenance and/or testing.

The inspector observed instrumentation and control (I&C) technicians perform portions of procedure 8.M.1.29, ATWS Trip Unit Calibration Test. The inspector discussed the procedure with the technicians who were knowledgeable of the system and the high risk nature of the testing. The technicians used good self checking techniques and performed the calibration in accordance with the procedural instructions. During the test, one of the technicians noted that procedure clarity problem but, he correctly discussed this with his supervisor and noted the discrepancy in the comment section to have the procedure reviewed. In addition, one of the technicians noted an improper catch containment on nearby instrumentation and notified radiation protection to get it resolved. This issue is further discussed in Section 5.3. In summary, the I&C personnel properly completed the procedure and used the prescribed self-checking initiative.

During I&C performance of procedure 8.M.2-2.2.1, Recirculation System Differential Pressure, the inspector observed good procedure adherence, radiological protection practices, and self checking techniques. The inspector observed the technician tapping the "local" pressure gauge before taking the calibration readings. The technician indicated that this practice was allowed by the vendor manual since the mechanical linkages in the gauge sometimes bind. The inspector discussed this practice with I&C supervision and other technicians and reviewed the vendor manual and confirmed that this practice was acceptable.

The inspector observed portions of I&C instrument functional procedures 8.M.2-2.5.1, High Pressure Coolant Injection Steam Line High Flow Isolation, and 8.M.2-2.6.1, Reactor Core Isolation Cooling Steam line High Flow. The procedures were similar for the two systems and were performed by the same operators and I&C technicians. The inspector observed the tests from the local pressure transmitters for one test and from the control room and cable spreading rooms to get a complete view of the conduct of the surveillance. The inspector noted excellent communication between the I&C technicians in the cable spreading room and at the local instruments and between the control room and I&C technicians. Both tests were well controlled and all values were within the acceptable limits.

3.2 Salt Service Water (SSW) Bay Configuration During Portion of Screenhouse Instrumentation Upgrade

After a December 12, 1993, intake structure loss of water level event (documented in IR 93-23), BECo initiated an event review team to identify the root cause of the event and recommend corrective actions. The team recommended that the plant's existing screenhouse instrumentation be enhanced to provide local indication of level in all areas of the intake structure. PNPS is in the final stages of upgrading the previous instrumentation and installing additional instrumentation in the intake structure and bays. This work was done in accordance with Plant Design Change (PDC) 94-31A, Screenhouse Instrumentation Upgrade - Phase 2. As part of this upgrade, bubbler tubes and stilling wells were installed in the bays for the safety-related SSW pumps. During this period, divers were sent into the bays to secure the stilling wells to the SSW cubicle enclosure walls.

The inspector observed the diving activity in the SSW bay near the "B" SSW pump. During this work, the "B" SSW pump was tagged out of service and the appropriate tracking LCO followed. The diver entered the water above the "C" pump and swam to the "B" pump. The "C" SSW pump has an automatic start feature. The inspector reviewed the pre-work briefing sheet and discussed the system configuration with the operators and diving contractor personnel. All were aware of the tagging of the "B" pump and possible auto-start of the "C" pump. The inspector observed caution by the diver while near the C pump. The inspector verified the diving personnel performed work in accordance with the appropriate in process control sheet and maintenance request instructions.

During this evolution, the inspector noted that the normally-closed rear sluice gate, which separates the "A", "B", and "C" pumps from the "D" and "E" pumps, was open and the normally open west sluice gate was closed. This minimized the flow rate into the bay where personnel were working. Therefore, water was supplied to all pumps through the normally-open east sluice gate and to the "A", "B", and "C" area through the rear sluice gate. The inspector questioned whether this configuration was allowed per plant design.

When the plant was originally licensed, the opening in the rear of the SSW bay did not have a gate. FSAR Section 10.7 for the SSW system states that the rear gate was installed to improve the flow condition in the bay. The gate was installed by PDC 77-44 to facilitate the dewatering of each side of the service water bay to install other modifications and also to improve flow conditions near the "A" and "D" pumps to minimize flow induced pump vibration. The gate was not installed for separation criteria. Since installation, the gate has been maintained normally closed. During early 1994, further root cause investigations were performed and determined that the SSW pump vibration problem was caused by resonance at the motor shaft running speed more than bay flow patterns. Therefore, operation with the rear sluice gate open is acceptable and affects neither separation criteria nor operability of the SSW system. The inspector concluded that this maintenance activity, which required the use of divers, was well controlled.

3.3 (Closed) Unresolved Item 50-293/94-18-03: Maintenance Performance Weaknesses

Several maintenance performance issues were documented in section 3.0 of NRC inspection report 50-293/94-18. For example, poor maintenance work was evident during outages for the station blackout and emergency diesel generators during August 1994. As a result, BECo initiated a task force to evaluate maintenance performance issues and develop and implement corrective actions to improve performance. A maintenance improvement plan (MIP) was initiated which was broadly focused and performance oriented. NRC inspection report 50-293/94-26 documented a licensee identified violation concerning the failure to maintain containment integrity due to not reinstalling a pipe plug into a drywell/torus differential pressure transmitter low pressure port. The worker errors occurred in November 1994. After holding an enforcement conference, the NRC issued a Severity Level III violation.

In response to the violation, BECo referenced the MIP which was in the process of being implemented when the missing pipe plug was discovered. Maintenance workers generally performed well during refueling outage No. 10 (RFO10) as documented in NRC inspection report 50-293/95-09 and 13. Some instances of maintenance rework occurred, especially involving contract workers. In addition, the maintenance performance indicators being developed needed further enhancement.

After the completion of RFO10 several substantial changes were implemented as part of the MIP. A new and updated work control process was implemented. Implicit in the new maintenance process was an emphasis on pre-planning and work scheduling. A new work control department was formed utilizing the work week manager concept. As part of the downsizing initiative, the maintenance manger position was eliminated, and the mechanical and electrical groups were combined. Additionally, a work-it-now (WIN) team was formed to allow more efficient repair of minor maintenance items within the skill of the trades.

Since the completion of RFO10 (mid June 1995), the maintenance request backlog has been worked down from approximately 700 running repair items to 450 running repairs, with an aggressive 1996 goal established at 200-250. Improvements have been made in the performance indicators including maintenance rework and a related maintenance quality indicator. A goal of 3% maintenance rework has been established. Positive maintenance worker performance was observed by the inspector during reactor core isolation cooling and high pressure coolant injection outages during the past few inspection periods. Additionally, no major plant equipment worked on during RFO10 required rework or power reductions. Lesson learned briefings are given every Wednesday during the plant manager's morning meeting to discuss work quality, progress and clearly identify work impediments.

Based on the above improved maintenance worker performance, and the continued efforts to use performance indicators, this unresolved item is considered closed.

4.0 ENGINEERING (37551, 92903)

4.1 (Update) Unresolved Item 50-293/95-21-02: Elevated Salt Service Water (SSW) Temperatures

4.1.1 Purpose and Inspection Scope

During the previous inspection period, elevated salt service water (SSW) inlet temperatures were experienced. Instantaneous SSW inlet temperatures went above 65 degrees Fahrenheit which is referenced in the updated safety analysis report (UFSAR) as the design value of the reactor building close cooling water (RBCCW) system and also used as an input parameter (assumption) in accident analysis calculations. SSW inlet temperature is measured by resistance temperature detectors (RTDs) installed at the inlet to each RBCCW system heat exchanger. The RTDs provide input to the EPIC computer which records the maximum ten minute average for every hour of SSW inlet temperature. Pilgrim has historically experienced elevated SSW inlet temperatures during August of each year. The inspector conducted a review of the Pilgrim licensing and design basis to assess BECo's actions to evaluate the effects of elevated SSW inlet temperatures. Related SSW issues are documented in Engineering Report Details (Section 3).

4.1.2 Background

For background information, the inspector reviewed the UFSAR and technical specifications (TSs) relative to the design and licensing basis information for the SSW and RBCCW systems including the accident analysis. TS do not have any specific requirements for a maximum SSW inlet temperature. The UFSAR contains the following information: (1) Section 10.5.5.3, RBCCW System Accident and Transient Operations, assumes a SSW inlet temperature of 65 degrees Fahrenheit to satisfy the design residual heat removal heat load and additional other essential heat loads (2) Table 14.5-1, Loss of Coolant Accident Primary Containment Response Summary, assumes a SSW inlet temperature of 65 degrees Fahrenheit (3) Section 14.5.3.1.3, Core Standby Cooling System Net Positive Suction Head, uses a **maximum** SSW inlet temperature of 65 degrees Fahrenheit as an analytical accident analysis calculation input value and, (4) Figure 2.4-2, Maximum, Minimum and Mean Temperatures For Cape Cod Bay and Boston Tide Stations, provides general hydrology sitting criteria for the PNPS. The inspector noted that the existing version of the UFSAR describes the SSW inlet temperature as a discreet value for the RBCCW design value and as an assumption for accident analysis calculations.

The inspector reviewed the area of elevated SSW inlet temperatures in three parts including the basis for continued plant operation when SSW inlet temperatures exceed 65 degrees Fahrenheit, interim actions including procedural guidance provided to the operators and a historical perspective of previous actions to evaluate elevated SSW inlet temperatures.

4.1.3 Basis for Continued Operation

The first aspect of this review involves the basis for continued operation when SSW inlet temperatures exceeded 65 degrees Fahrenheit. The inspector reviewed the elevated temperatures that occurred during the summers of 1994 and 1995. Problem Report (PR) 94.9297 initiated on July 7, 1994 documented that SSW inlet temperatures reached 67 degrees Fahrenheit which exceeded the RBCCW design limit. Part "D", Screening and Problem Assessment Committee (PAC) Review, of the PR listed this elevated temperature as a hardware nonconforming condition. On August 5, 1994, the operations review committee (ORC) reviewed and approved an engineering evaluation that concluded the RBCCW system is operable with SSW inlet temperatures up to 75 degrees Fahrenheit. The engineering evaluation served as an operability evaluation using NRC Generic Letter 91-18 as a guide. Also, BECo initiated actions to resolve the nonconforming condition by developing a design report with a 10 CFR 50.59 safety evaluation scheduled to be completed by the start of Summer months of 1995 when elevated SSW temperatures would return.

On August 3, 1995, the engineering manager issued a memorandum to the plant manager authorizing SSW inlet temperature excursions above 65 degrees Fahrenheit. The memo classified the elevated SSW inlet temperatures as a design adequacy issue and **not** a licensing conformance issue. Engineering personnel determined that it was expected that the selected SSW design inlet temperature of 65 degrees Fahrenheit might be exceeded occasionally during the months of June, July, August, September or October. Further, the memorandum stated that the average monthly temperatures should not exceed 65 degrees during any month. The inspector noted that this is when BECo began to apply a rolling 30 day average as the SSW inlet temperature limit. The design report package initiated from PR 94.9297 was not completed before the return of elevated SSW inlet temperatures during the Summer of 1995.

On August 7, 1995, the engineering manager issued another memorandum to the plant manager establishing a rolling eight hour average of 75 degrees as the design basis accident short term response limited by component equipment qualification and residual heat removal and core spray pump net positive suction head. The long term response was limited by the rolling 30 day average of 65 degrees Fahrenheit. The memorandum concluded that no compensatory measures, including power reductions, were recommended and that if a rolling eight hour average of 75 degrees Fahrenheit was exceeded, the operators should contact engineering for further evaluation. BECo interpreted Regulatory Guide 1.27, revision 2 (Draft), "Ultimate Heat Sink for Nuclear Power Plants," as allowing the establishment of a rolling 30 day average.

During the previous inspection period (IR 95-21), a rolling 30 day average of SSW inlet temperature exceeded 65 degrees, reaching a maximum 30 day average of approximately 67 degrees Fahrenheit. The 30 day average was exceeded from August 24 to September 17, 1995. Engineering personnel identified this on September 4, 1995 while reviewing temperature data as an input for the design report to be used to update the UFSAR. Engineering personnel initiated PR 95.9485 on September 4, 1995 to document and evaluate the exceedance of the rolling 30 day average temperature of 65 degrees Fahrenheit. On September 14, 1995, the engineering manager issued another memorandum authorizing a new SSW inlet temperature limit of a rolling 30 day average temperature of 67 degrees Fahrenheit. The memorandum noted that, although the drywell temperature analysis for the steamline breaks, safe shutdown Appendix R analyses and anticipated transient without scram (ATWS) analyses were affected, the conclusion of the related analyses remained valid. Based on this, BECo determined that the 67 degree rolling 30 day average was not a safety concern.

During the previous inspection period, the inspector held several meetings with engineering personnel to review pertinent documents and memorandums. The inspector identified a concern that a 10 CFR 50.59 safety evaluation had not been completed to determine whether or not an unreviewed safety question existed. The inspector determined that operation of the plant with elevated SSW inlet temperatures greater than 65 degrees Fahrenheit was a de facto change to a system or procedure described in the UFSAR. Also, the adequacy of using a rolling 30 day average temperature was questioned. The assistant engineering manager informed the inspector that a 10 CFR 50.59 safety evaluation could not be completed until the design report package, intended to be used to update the UFSAR, was completed. Further, engineering management stated that NRC Generic Letter 91-18 allowed continued plant operation without prompt resolution of the nonconforming condition by completing a 10 CFR 50.59 safety evaluation or making hardware changes, if needed. The inspector disagreed with this use of Generic Letter 91-18. Specifically, a corresponding 10 CFR 50.59 safety evaluation to allow continued plant operation with a nonconforming condition when SSW inlet temperatures exceeded 65 degrees Fahrenheit was not completed to ensure an unreviewed safety question did not exist.

Plant management indicated to the inspector that they would complete the design report package including a 10 CFR 50.59 safety evaluaticn by the end of March 1996 before elevated SSW inlet temperatures return. The NRC Region I staff initiated administrative action to have the Office of Nuclear Reactor Regulation (NRR) formally review the current Pilgrim licensing and design basis to assess the adequacy of BECos actions relative to elevated SSW temperatures.

4.1.4 Interim BECo Procedural Review Actions

The second aspect of this review was on the approved procedural guidance provided to the operators concerning SSW inlet and RBCCW temperature limits. Three concerns were identified. The first concern was that the SSW operating procedure (2.2.32) contains an administrative limit stating that the RBCCW system remains operable with SSW inlet temperatures up to 75 degrees Fahrenheit. This administrative limit was added on February 23, 1995 as part of procedure revision 35. The inspector reviewed the associated procedure change notice and preliminary evaluation checklist (PEC) to determine the basis for the change. All screening questions in the PEC were checked "NO" by operations support engineers; thus, no 10 CFR 50.59 safety evaluation was performed.

More specifically, the inspector identified the following deficiencies with the procedure change: (1) One PEC question "Would this change assumptions used in the accident analyses described in Chapter 14?" was answered "NO" instead of "YES". UFSAR Section 14.5.3.1.3 and Table 14.5-1 assume a SSW inlet temperature of 65 degrees Fahrenheit. If properly checked "YES", a 10 CFR 50.59 evaluation would have been required. (2) The procedure change preparer did not correctly identify all pertinent UFSAR sections affected by the change and, (3) Revision 35 also changed the allowable plugging limits for the RBCCW heat exchangers as analyzed by safety evaluation 2892; however, this safety evaluation used 65 degrees Fahrenheit as an input parameter. The licensee initiated PR 95.9493 to address the inspector's concerns. Although not documented on the procedure change notice or PEC checklist, the operations support engineer verbally referenced the August 1994 engineering evaluation as the basis for completing the procedure change without completing a 10 CFR 50.59 safety evaluation.

The second concern was related to the interim action used to provide operators guidance using Operations Standing Order 95-09, dated August 11, 1995. This standing order modified the above procedural limit of 75 degrees to a rolling eight hour average limit of 75 degrees Fahrenheit. Further, the order instructed operators to contact engineering for evaluation if the new rolling eight hour limit was exceeded. The question also arose on the adequacy of a procedure step for operations to notify the engineering organization for an evaluation of conditions when an apparent absolute limit was exceeded. The inspector expressed concern to the operations manager that standing order 95-09 did not meet the intent of procedure 1.3.54, Operations Standing and Night Orders, which specifies that neither standing orders nor night orders may supersede or modify existing plant procedures. Further, the BECo quality assurance manual specifies that changes to procedures are reviewed, approved, controlled and distributed in the same manner as the original issue. Also, the use of uncontrolled documents in lieu of procedural processes (such as memos in lieu of procedure changes) is forbidden. The memorandums provided from engineering to the plant manager as described in Section 4.1.2 above, also did not meet the intent of the BECO quality assurance manual. Shortly after the end of this inspection period, the operations manager retracted operations standing order 95-09 alleviating the procedure adequacy question noted above.

A third concern was related to third interim action involving engineering personnel adherence to procedure NOP83E5, NEDWI 395, which specifies that a PEC be completed for each operability evaluation. The August 1994 operability evaluation for elevated SSW inlet temperatures did not have an attached completed PEC checklist to determine whether or not a 10 CFR 50.59 safety evaluation was needed to determine whether or not an unreviewed safety question was involved. The licensee initiated PR 95.0638 on August 5, 1995 to evaluate this issue.

In conclusion, the BECo interim procedural/review actions, including guidance provided to operators, were handled informally through the use of operations standing orders, memorandums between engineering and plant management, operating procedure changes without the requisite 10 CFR 50.59 safety evaluations, and the lack of a completed PEC associated with the August 1995 operability evaluation. Since some of these concerns are somewhat related to the fundamental problem that a 10 CFR 50.59 safety evaluation was not completed in August 1994, the final disposition of these interim issues is pending further NRC staff review. The executive vice president agreed at the inspection exit meeting to start review of these concerns.

4.1.4 Historical Perspective

The third aspect of this review was on relevant historical documents to asses the vigor which BECo applied to maintain the Pilgrim licensing basis concise and up-to-date. In response to elevated SSW inlet temperatures, BECo submitted in 1984, a TS change (84-T-13) which included analysis for SSW inlet temperatures at 65, 70 and 75 degrees Fahrenheit. The TS change was not approved by the NRC and was subsequently retracted by the licensee. Another related TS change (85-T-10) was prepared by BECo which defined the SSW flow requirements as a function of differential pressure across the RBCCW heat exchanger tubes assuming a maximum inlet temperature of 75 degrees Fahrenheit. BECo did not submit the proposed TS change. In response to IEN 87-65, Plant Operation Beyond Analyzed Conditions, BECo identified that the maximum assumed SSW inlet temperature of 65 degrees Fahrenheit used as an accident analysis input parameter was not conservative. Actual temperatures up to 72 degrees had been experienced. The recommended TS and FSAR changes were never implemented. More recently in 1994 and 1995, the engineering staff would not rely on these previous safety analyses for elevated SSW inlet temperatures. The previous evaluations did not fully envelope all effects of elevated SSW inlet temperatures. More industry operating experience was available and more rigorous licensee requirements have been imposed on completion of 10 CFR 50.59 safety evaluations. The inspector determined that elevated SSW inlet temperatures have been experienced before at Pilgrim.

4.1.5 Conclusions

Although BECo did not aggressively resolve the issue of elevated SSW inlet temperatures and the interim actions are of concern, the actual RBCCW safety function appears not to be compromised. A draft version of the design report package, including General Electric Company computer model analyses, concluded that instantaneous temperatures up to 75 degrees Fahrenheit is acceptable. However, pending NRR's evaluation of the current Pilgrim licensing and design basis of the SSW system, the BECo interpretation of the documented licensing basis, and basic understanding of 10 CFR 50.59 requirements remain a regulatory concern. This area will remain **open** as an unresolved item pending submittal to NRC of the BECo UFSAR revision and subsequent NRC staff review disposition. **(UNR 50-293/95-21-02)**

4.2 Loose EDG Foundation Anchor Bolt Nuts

During a routine safety system review on October 12, 1995, the inspector identified approximately four or five loose anchor bolt nuts on each emergency diesel generator (EDG). Full thread engagement between the nuts and anchor bolts still existed despite being hand loose. Each EDG is secured to a concrete foundation pad using fourteen 1.25 inch diameter anchor bolt and nut arrangements. The inspector informed the nuclear watch engineer (NWE) to assess any immediate operability concerns. The NWE visually inspected the loose anchor bolt nuts with the inspector and then immediately contacted engineering for evaluation. Problem report 95.9535 was initiated to document, evaluate and implement corrective actions, as required.

Licensee engineering personnel considered the loose anchor bolt nuts to be a hardware degraded condition. The EDGs remained operable. Design drawings indicated that a 50 ft-lb installation and thread staking achieves a snug tight condition as a good practice to prevent the nut from backing off. However, the anchor bolt, washer and bedplate design can accommodate small EDG movement (e.g., vibration) and this anchorage system does not depend on a specific preload to perform its function of securing the EDG to the concrete pad. The as-found conditions met functional requirements. The inspector did not identify any concerns with this initial operability determination.

That same day, the work-it-now (WIN) maintenance team torqued the anchor bolt nuts to 50 ft-lbs as intended in the design drawing. The bolt threads were staked. Subsequently, the inspector again examined the anchor bolt nuts identifying no problems. On October 25, 1995, the licensee closed PR 95.9535. The inspector reviewed the completed PR to review the root cause of the loose anchor bolt nuts. The PR did not completely address the corrective actions needed to consider the effectiveness of measures to ensure the anchor bolt nuts do not back-off again. For example, the PR did not address whether or not the nuts loosened due to improper staking of the anchor bolt threads and also whether or not a periodic preventative maintenance task needs to be developed to verify the torque of the EDG anchor bolt nuts. The inspector discussed these questions with the regulatory affairs department manager who indicated that although not documented in the PR, the EDG system engineer was evaluating the need for additional longer term actions. The inspector had no further questions or concerns relative to this issue.

The inspector concluded that the licensee took appropriate actions to correct an NRC identified degraded condition involving the EDG anchor bolt nuts. The NWE and engineering personnel worked together closely to complete the initial operability evaluation. The loose EDG anchor bolt nuts represents a weakness in that the system engineer or mechanical maintenance workers did not previously identify this deficiency.

4.3 Review of the Operating Experience Review (OER) Program and Vendor Equipment Technical Information Program (VETIP)

The scope of this inspection involved the performance of a review of the OER and VETIP processes and programs to verify that written program controls were being adhered to. Also, the inspector reviewed personnel staffing of these programs to assess to what degree BECo's restructuring and reorganization in the nuclear organization (NUORG) was affecting the proper implementation of these programs. The inspector conducted interviews with staff personnel and managers responsible for program implementation, reviewed procedures and documentation, and reviewed self-assessment and Quality Assurance (QA) activities to assess how they contributed to management's oversight of these programs. The inspector also reviewed BECo's use of vendor manuals (VMs) in conducting maintenance on safety-related (S-R) components.

4.3.1 Program Background

<u>OER</u>

The OER Program, which has it's origins in NUREG-0737, Section I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff", is controlled through the implementation of procedure NOP8401, Rev. 6, Operating Experience Review Program. This program is used by the NUORG to ensure that lessons learned from industry operating experience are translated into preventive or corrective actions to improve plant safety and reliability.

VETIP

Several programs originated from commitments made by BECo as a result of the issuance of NRC Generic Letters (GLs) 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events," and 90-03, Relaxation of Staff Position In GL 83-28, Item 2.2 Part 2, "Vendor Interface for Safety Related Components". The VETIP establishes NUORG program requirements for the control and validation for VMs and other technical documents associated with the installation, operation, testing, design and maintenance of equipment installed at the plant. Whether the information is obtained from outside sources or provided by BECo internally, it is called equipment technical information (ETI). The Vendor Interface Program (VIP), which is actually a subset of the VETIP, was established to provide periodic contact with equipment manufacturers to verify the adequacy of supplied technical information for safety-related (S-R) components. The VMs, the equipment they cover, and the associated documents are listed in the Vendor Manual Information System (VMIS). According to the VETIP Coordinator, there were approximately 570 VMs in the VMIS of which 177 were S-R.

The VETIP and VIP are controlled through the implementation of procedure NOP84A4, Rev. 6, Vendor Equipment Technical Information Program. In Letter 93-030 to the NRC, dated March 1, 1993, BECo updated commitments related to these GLs. BECo clarified the elements of the VIP, as prescribed in GL 90-03, and specified that the elements are included in the existing scope of the VETIP. The VIP includes all S-R components within the nuclear steam supply system (NSSS) scope of supply and other key S-R components not included in the NSSS scope. Procedure NOP84A4 establishes periodic contact with the equipment manufacturer to verify the adequacy of supplied ETI. The inspector noted that neither the GL nor the procedure are specific about the periodicity requirements for contact with equipment manufacturer/suppliers included in the VIP. The Vendor Manual Change Request (VMCR) provides the process that is used to modify the contents of approved VMs.

A BECo contract with General Electric Co.'s Vendor Manual Subscription Service (VMSS) provides for a yearly update of vendor manual information on NSSS scope of supply components (approximately 194 items contained in 50 manuals of the VMIS). The other suppliers of key S-R components receive vendor interface contact reviews on an approximately 2-year basis (approximately 127 manuals of the VMIS).

4.3.2 Program Management and Coordination

COMBINED COORDINATOR

Both OER and VETIP programs are currently the responsibility of a single Senior Program Engineer (SPE) in the Technical Programs Division (TPD), who is required to fulfill the duties of the OER Coordinator and VETIP Coordinator as specified in the above enumerated procedures. The inspector was informed that a pending organizational re-alignment has been announced that will transfer the responsibility for these programs and the SPE from the TPD Manager to the Operations Support Division Manager. Both Programs have similar elements in their respective processes, such as: identification of items to be included in the program, screening of the items, evaluation, action and closeout for each item identified as being applicable to the program. The inspector noted that the position description NUORGPD-199 used by BECo to describe the duties and the responsibilities of the SPEs was not current in that it did not describe involvement in the VETIP. The TPD manager acknowledged the inspector's comments on this item. Also, procedures NOP8401 and NOP84A4 are not specific about the periodicity of program status reports that are issued to management.

<u>OER</u>

The OER Coordinator screens and forwards OER documents for evaluation to various departments within the NUORG. Action items are assigned a tracking number that are then entered into the Integrated Action Data Base (IADB). The inspector reviewed the OER Program status report dated March 2, 1995. This report covered the period February 1 through February 28, 1995 and was the last periodic status report issued by the TPD to the NUORG. The average age of 27 overdue screening action items assigned the OER Coordinator was 34 days. An updated report dated October 3, 1995, which was generated in response to the inspector's request, indicated that there were 18 overdue screening action items assigned to the OER Coordinator with an average age of 74 days.

This was due, in part, to the assignment of the OER/ VETIP Coordinator as a backup to the Master Surveillance Tracking Program (MSTP) Coordinator. From February 21 through May 30, 1995, he performed 100 percent of the duties of the MSTP Coordinator and a few of the more safety significant screening action items required to be performed by the OER and VETIP Coordinators.

Self-Assessment Reports performed by the TPD for April and June, 1995 clearly indicated the OER program fell behind due to refueling staffing re-allocation and that progress on reducing the backlog was slow. Although the TPD Manager indicated that he identified plans to alleviate the noted performance, no actions were taken by operations management to appropriately address this performance issue. However, the QAD Manager issued on September 21, 1995 a Self-Assessment Report that was developed by a NUORG team which documented concern in this area. Specifically, the report stated that the OER Coordinator was routinely used as outage support or used to replace another that has been used for outage support and this causes a delay and development of a backlog impacting the timeliness of transfer of information to the individuals that can take the correct action. As of the end of this inspection period, BECo actions to address this resource problem were being developed. The inspector identified no immediate safety implications resulting from the OER Coordinator's screening backlog.

<u>VETIP</u>

While the VETIP Coordinator processes all ETI and correspondence received through the GE VMSS and receives and screens VIP responses and ETI, the actual ownership of the VMs, according to the procedure, is assigned to individuals by owner division managers. For the most part, the inspector determined that engineers (both systems and design engineers) are the owners of the VMs and are therefore required to review and evaluate ETI and to process the VMCRs.

However, it is the NUORG division managers the are required to ensure that all action items assigned to their division are completed in a timely manner. It is the responsibility of the QAD Manager for assuring the performance of regular vendor interface contacts with vendors, with the exception of vendors covered in the GE VMSS, and in assuring all requested VM information is received and forwarded to the VETIP Coordinator. It is the Procurement Quality Engineering (PQE) Group that performs the actual vendor contacts for the S-R VMs.

4.3.3 Vendor Manual Updates and VIP Implementation

The inspector's review of the number and status of action items in the IADB for the VETIP/VIP indicated the existence of a significant backlog problem that related to the number of evaluations of ETI that were waiting for engineering personnel to formally assess the items' impact on the technical adequacy of the VMs or the need to process a change. The most recent VETIP status report issued to the NUORG by the TPD Manager was dated March 2, 1995 for the period February 1 through 28, 1995 indicated that there were 195 ETI evaluations open with an average age of 441 days. The inspector requested and received an updated VM IADB status report that was dated October 2, 1995 which indicated that there were 176 ETI evaluation items open, and of these there were a total of 119 action items to evaluate ETI for VMs that were overdue for a period of between 1.5 to 3.25 years.

A review by a Nuclear Engineering Services Department self-assessment team completed on September 12, 1994 determined that it was difficult to make VM revisions resulting in VM revision backlog. On November 29, 1994 BECo compliance personnel were following up on a concern expressed by the Licensing-Compliance Division Manager that the VMs are not being maintained current. Their effort reviewed industry guidance to determine the appropriate time frame in which to make changes to the VMS such that they would be maintained in a current state. Since they determined that 6 months was a reasonable time frame, they issued Problem Report (PR) 94.0581 to identify and address the issue within the BECo Corrective Action System. By March 17, 1995 a number of corrective actions were established to address the cause of the average age of VM related open items being excessive, including: establishment of a task force to provide recommendation to streamline the VM change process to ensure that regulatory requirements are met, provide changes to the procedure NOP84A4, conduct division level training when the revised procedure is issued, establish a team of engineers from each discipline to reduce the backlog of VM changes, establish a VM coordinator to handle support tasks that are currently performed by engineers, train division clerks to perform the administrative portions of the VM changes, and have Nuclear Engineering Managers review the distribution of VM assignments of ownership to determine if a more even distribution across engineers is possible.

The inspector noted that the PR evaluation provided a basis that the condition was not a problem because untimely VM changes had not contributed to problems, only a third of the overdue manuals are safety related, the system engineers (SEs) were cognizant of both planned work on their systems and the nature of material that was in backlog that could affect the validity of information contained in the VMs, and work control process changes were to solidify the

SEs involvement in work package planning and provide a mechanism for them to identify outstanding vendor manual revisions which may impact work. Not withstanding these considerations, the inspector questioned the potential impact on S-R maintenance currently done with VMs not updated, and therefore reviewed the current status of the corrective actions. The inspector learned that the reassignment of cognizant personnel to support the recent refueling outage, as well as other work load priorities, had caused the schedule for the items to slip. During discussions with BECo management representatives about the apparent need to revisit the nature and status of corrective actions for the issue, the inspector was informed of additional actions that would be developed in the near term to ensure that planned work that relied on VM content would not be negatively impacted until the VM backlog issue would be resolved.

Subsequently, on October 6, 1995 the Nuclear Engineering Services Group (NESG) Manager issued a memorandum to the NUORG that effectively addressed the issue of performing maintenance on S-R components while a VM change is outstanding. Until the program revision is developed to correct the issue: (1) all open VM action items would be reviewed by the owner of the VMs by October 20, to identify in writing those VMCRs that will be required to perform maintenance on the component, (2) the SEs would then place a hold on Maintenance Requests effected by the VMs, and (3) any new VMCR that was subsequently generated that is required to perform maintenance on a S-R component will have the change request completed in 30 days.

On October 23, the NESG manager issued a revised schedule for the PR corrective actions. An added action required that the team established to develop a plan to reduce existing backlog of VM changes would include development of performance indicator(s) to monitor work backlog, method of trending progress, and appropriate management action levels to maintain progress. The schedule called for completing the enumerated team actions by December 11, 1995 and to reduce VM backlog to meet the acceptance criteria contained within the performance indicator(s) by April 1, 1996.

The inspector identified that a number of backlogged QAD action items involving vendor contacts for the VIP existed and that the Supervisor of PQE, who is the owner of these items, was not aware that several items were still open and required action. This was explained to be the result of personnel changes that had occurred in this program area. Actions were taken by the VETIP Coordinator to re-issue action item work packages to address these oversights. Based upon the inspector reviewing a sampling of completed VIP data packages, the inspector identified an additional problem that once the PQE conducted vendor contact identified that updated ETI existed and the information was to be submitted to BECo, the vendor contact action item in the IADB was closed even before the material was received by BECo. In the few cases that were identified by the inspector, the ETI was subsequently received and processed. This premature action item closure practice was brought to the attention of the VETIP Coordinator, who acknowledged that the aforementioned practice was unacceptable and would be discontinued.

4.3.4 Use of VMs During Maintenance

The inspector reviewed a number of S-R equipment maintenance procedures and procedure 1.5.20, Work Control Process, to assess the use of VMs as part of conducting work on S-R components. In procedure 1.5.20, instructions are provided for work plan organization and content in that the work plan may refer to steps contained in VMs. A number of preventive maintenance procedures for the emergency diesel generators that were reviewed by the inspector directs the use of the applicable VMs (V-0251 and V-0454) for both preventive and corrective maintenance. Also, the inspector noted that procedure 3.M.4-10, Valve Maintenance, references VMs and directs that valve assembly and disassembly can be performed according to manufacturer instructions and provides information on obtaining the applicable VM. No specific concerns related to outstanding VM action items potentially causing impact on the conduct of S-R maintenance were identified by the inspector during this review.

A number of Maintenance Requests involving S-R maintenance reviewed by the inspector were noted to direct the use of VMs in conducting the activity. Based upon interviews with BECo personnel involved with the planning and conduct of maintenance, and those responsible for the generation and maintaining of VMs, the inspector determined that BECo relies on the use of VMs to conduct maintenance.

4.3.5 Summary of Major Findings and Conclusions

<u>(OPEN) Unresolved Item (50-293/95-22-01): BECo Corrective Actions to Resolve VETIP Backlog.</u> The inspector identified no regulatory prohibitions that would preclude BECo from assigning the OER and VETIP Program Coordinator responsibilities to a single SPE (Section 4.3.2). Weak program management and coordination was evident in BECo's performance in the areas of: (1) delayed initial screenings that were to be conducted by the OER Coordinator and the excessive backlog by VM owners in performing required evaluations (Sections 4.3.2 and 4.3.3); (2) procedures NOP8401 and NOP84A4 are not specific about the periodicity of program status reports that are issued to management (Section 4.3.2); (3) infrequent program reports about the details of the backlog issue were being provided to the Senior NUORG managers (Sections 4.3.2 and 4.3.3) ; and (4) self assessments and identified corrective actions were not being effectively used by the managers to ensure that resource re-allocations would not unduly impact program performance (Section 4.3.2). It did not appear to the inspector that the observed program performance was related to BECo restructuring efforts. However, resource diversion associated with supporting outage related priorities did negatively impact the OER Program and VETIP. Self-assessments conducted by the NUORG, including the QAD, were effective in identifying program deficiencies. The effectiveness of BECo Corrective Action or VETIP backlog as noted above is unresolved **(50-293/95-22-01)**.

It was evident that BECo is aware of their regulatory commitments for updating S-R VMs so that they will be maintained current and that a program was in-place that required the updating of VMs. Also, reliance on VM information, whether directed by procedures or work plans, was evident during the conduct of maintenance on S-R components.

The inspector determined that BECo managers responsible for VM related action items involving ETI evaluations failed to follow NUORG procedure NOP84A4 requirement to ensure that all action items assigned to them are completed in a timely manner. The TS administrative controls require that S-R procedures by properly implemented. While this failure resulted in the creation of an excessive backlog and unacceptable delays in the processing VM revisions, it was of low safety significance because there have been no identified deficiencies resulting from this condition during the performance of S-R maintenance. Also, appropriate short-term and long-term corrective actions have been identified by BECo to resolve this deficiency. This failure constitutes a violation of minor safety significance and is being treated as a non-cited violation consistent with Section IV of the NRC Staff enforcement policy.

5.0 PLANT SUPPORT (71750, 92904)

5.1 Emergency Preparedness (EP) Functional Drill

A dry run EP drill was conducted on November 8, 1995 in preparation for the emergency response organization and offsite agency response for the December 13, 1995 full participation, NRC/FEMA evaluated exercise. The inspector observed portions of the drill in the technical support center (TSC). The drill scenario (simulation) involved a loss of offsite power and a failure to scram causing some core damage. During the transient, the safety relief valves opened briefly. Two main steam system safety valves discharge directly into the drywell atmosphere, while the four safety/relief valves used in the automatic depressurization system discharge to the torus. An Alert was declared and evaluation of an increasing trend of the containment high range monitoring system (CHRMS) was in progress.

The inspector observed that the licensee personnel, who were assigned duties for core damage assessment, experienced difficulty using procedure EP-IP-330, Core Damage, to assess the level of core damage and provide timely and meaningful input to the emergency plant manager (EPM). Specifically, the intent and use of the containment radiation vs. time composite graph located in Attachment 4 of EP-IP-330 was not fully understood. Some licensee personnel believed that the curve could only be used concurrent with a loss-of-coolant-accident (LOCA) event, as implied by the procedure, while others believed the curve could be used to provide an estimate of core damage during any accident scenario. As a result, a long discussion (approximately 30 minutes) occurred and no detailed core damage assessment information was provided to the EPM before the scenario progressed to the next plateau of a site area emergency.

The inspector held a meeting during this inspection period with the emergency planner for EP drills and exercises to review the licensee findings of the November 8, 1995 drill. Preliminarily, the licensee identified no major deficiencies that might impede efforts to protect the health and safety of the public. However, three weaknesses were identified; one of which involved the subject uncertainty of the applicability of the core damage assessment procedure to non-LOCA conditions. The emergency planner informed the inspector of corrective actions planned to address the core damage assessment weakness. A change was made to procedure EP-IP-330 to clarify the use of core damage assessment during non-LOCA conditions. The licensee determined that the radiation vs. time composite graph could be used during any accident event as an estimate of core damage. Also, remedial training was scheduled and began during this inspection period to improve licensee personnel understanding of core damage assessment during non-LOCA accident scenarios.

The inspector made the following conclusions: (1) positive licensee performance was evident during the November 8, 1995 drill when the controllers preliminarily identified core damage assessment as a weakness (2) positive performance was evident during all other facets of the EP drill including all actions to protect the health and safety of the general public, and (3) an opportunity for improvement existed in core damage assessment during this practice drill, procedure changes and remedial training were planned. Additional inspection review occurred in NRC Inspection 50-293/95-22 (EP Exercise).

5.2 As Low As Reasonably Achievable (ALARA) Committee Meeting to Determine 1996 Dose Goal

The inspector attended a meeting of the ALARA committee on November 13, 1995. The purpose of this meeting was to discuss department radiological dose goals for 1996. The meeting was attended by appropriate department representatives including maintenance, operations, I&C, projects and construction, radiological protection, and chemistry. The meeting was chaired by the acting deputy plant manager. The inspector noted good discussion of each department's requested goal and action plan. An additional 10 percent was taken off each department's projected goal to make the final goal challenging. Because the committee was so critical of the department presentations, another meeting was set to allow the groups to further analyze their requests and formulate plans to reduce dose. The inspector considered the meeting to be productive in that the scrutiny given to each plan forced the departments to concentrate on ways to reduce radiological dose in 1996.

5.3 I&C Technician Identification of Unacceptable Catch Containment

As mentioned in Section 3.1, an I&C technician performing a surveillance on the ATWS trip panel identified an improper catch containment for an instrument valve on a nearby rack. The technician brought the condition to his supervisor's attention during the surveillance. The supervisor contacted station services who removed the catch containment that was in place and hung an approved catch containment below the leaking valve. The station service personnel installed the catch containment in accordance with the procedure and were careful not to affect the operation of the safety-related instrumentation on the rack. I&C appropriately initiated PR 95.0629 to document the problem and also initiated a maintenance request to repair the leakage. The inspector considered the I&C technician's identification of the problem to be noteworthy. Also the immediate actions to correct the plant condition and initiate the problem report showed I&C staff was sensitive to deficient conditions and used the proper processes to correct and document the problem.

5.4 Observation of Reduction of Contaminated Areas

BECo has an initiative to increase the percent of uncontaminated areas at Pilgrim. The goal was 95 percent; however, with the successful decontamination of many areas which were long-standing contaminated areas, the plant is considering setting a more challenging goal. At the close of the inspection period the plant was 93 percent uncontaminated. This decontamination effort was noted during a routine tour of the reactor building. The inspector noted that the door to the fuel pool cooling filter room was not posted as it had been in the past. The inspector discussed this condition with radiological protection personnel and found that the entrance to the area was decontaminated in August 1995. The inspector entered the room and noted that the proper radiological conditions were posted. This is a positive indication that progress has been made to decontaminate the plant and reach the current goal of 95 percent uncontaminated.

6.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES

6.1 Routine Meetings

Two resident inspectors were assigned to the Pilgrim Nuclear Power Station throughout the period. Back shift inspections were conducted on October 17, 19, 23, 24 and 30, and November 6. On October 26, Mr. Richard Conte, NRC Region I Branch Chief for Pilgrim, visited the site to tour the plant, interview senior level managers, and hold discussions with the resident inspectors. On November 1, Mr. Thomas T. Martin, NRC Regional Administrator for Region I, visited the site for a site tour and discussions with the residents. In addition, Mr. Martin held discussions with executive and department level managers.

At periodic intervals during this inspection, meetings were held with senior BECo plant management to discuss licensee activities and any areas of concern. After the conclusion of the reporting period, the resident inspector staff conducted an exit meeting summarizing the preliminary findings of this inspection on December 8, 1995. No proprietary information was covered in the scope of the inspection. No written material regarding the inspection findings was given to the licensee during this inspection period.

6.2 Other NRC Activities

From October 16 through 20, Dr. Jason Jang performed a routine effluent controls inspection. The results of this inspection are documented in NRC Inspection Report 50-293/95-34.

From October 2 through 6, Ms. Leanne Harrison conducted a routine fire protection inspection. From October 23 through November 3, Mr. Antone Cerne performed a routine engineering inspection. The results of these inspections are enclosed to the cover letter for this report.