U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.: 50-293

Report No.: 94-02

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

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: January 18 to February 21, 1994

Inspectors: J. Macdonald, Senior Resident Inspector
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Approved by: Gene Kelly 3/7/94
E. Kelly, Chief Date
Reactor Projects Section 3A

Scope: Resident inspector safety inspections were in the areas of plant operations, maintenance and surveillance, engineering, and plant support. Initiatives selected for inspection included assessment of storm preparations, infrequently performed surveillances, operating experience reviews, and off-site review committee activities.

Inspections were performed on backshifts during January 20, 21, 25, 28 and February 2, 4, 8, 10, 15, 16, and 18. Deep backshift inspections were performed on January 29 (12:00 noon to 6:00 pm) and February 21 (7:55 am to 2:35 pm).

Findings: Performance during this five week period is summarized in the Executive Summary.

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EXECUTIVE SUMMARY

Pilgrim Inspection Report 94-02

Plant Operations: Operators alertly observed the buildup of ice floats in the intake canal, and prompt actions were taken by shift supervision to reduce reactor power and initiate main condenser backwashing that quickly dissipated the ice. A Standing Order that directed preparations for approaching storms effectively addressed situations encountered in the intake structure during the December 13, 1993 storm. Operators properly isolated the 'D' main steam line as required by Technical Specifications, following failure of the associated inboard main steam isolation valve to close during surveillance testing.

Maintenance and Surveillance: The automatic depressurization system and the "B" emergency diesel generator were declared inoperable when they failed their respective surveillances. Maintenance technicians and system engineers developed comprehensive troubleshooting plans which effectively identified the failed components and allowed for successful repairs. Coordination between system engineers, operations, and maintenance personnel minimized the outage duration of the safety systems involved.

Engineering: The Operating Experience Review Program effectively evaluated past generic documentation regarding jet pump hold-down beam failures and pressure locking of motor operated valves. Engineers responsible for these technical areas were actively reviewing recent industry experience and, as a result, the Pilgrim-specific beam inspection periodicity is being re-evaluated. Similarly, modifications to address potential motor operated valve vulnerability to pressure locking have been integrated into the Fall 1994 midcycle maintenance outage schedule.

Plant Support: Radiological protection technicians properly established controls for high radiation areas created due to transient plant operations and system configurations. Generation of radiological problem reports to document these conditions enabled a cross section of plant disciplines to input into procedural guidance.

Safety Assessment and Quality Verification: Good questioning attitudes were displayed by system engineering personnel involved in the causal analysis of a high pressure coolant injection system isolation during December 1993 surveillance testing. The associated Licensee Event Report was thorough and properly addressed the reporting criteria. Recent changes to the membership and organizational structure of the Offsite Review Committee did not diminish effectiveness, as demonstrated by committee performance during the first meeting of the current year.

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DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

At the start of the report period Pilgrim Nuclear Power Station was operating at approximately 100% of rated power. On January 22, 1994, the 'B' emergency diesel generator was declared inoperable when it failed to attain rated speed within the required time period during a routine surveillance (Section 3.2). The once per cycle high pressure coolant injection system cold fast start test was completed satisfactorily on February 2, 1994 (Section 3.3). On February 3, the once per cycle reactor core isolation cooling system operability demonstration from its alternate shutdown panel was completed unsatisfactorily due to pump discharge flow oscillations. The system was verified to be operable from the main control room and appropriate compensatory fire watch inspections were performed. The test was subsequently completed satisfactorily on February 11, 1994 (Section 3.3). On February 4, 1994, the automatic depressurization system was declared inoperable due to a failed time delay relay that was identified during surveillance testing (Section 3.1).

Reactor power was briefly decreased on February 11, 1994, to conduct a main condenser backwash to dissipate ice floats in the intake canal (Section 2.2). Reactor power was decreased again on February 17, 1994, in order to return the 'A' recirculation pump speed control to the normal remote manual station in the control room. The 'B' recirculation pump motor generator set scoop tube was placed in the locked up position and temporarily instrumented with diagnostic equipment to identify the source of minor speed fluctuations. During the power reduction, the 'D' inboard main steam isolation valve (MSIV) failed its quarterly fast closure surveillance test. The valve was subsequently closed, as was the associated outboard MSIV, and the 'D' main steam line was isolated in accordance with Technical Specification requirements (Section 2.4). Reactor operation with a main steam line isolated is limited to approximately 75-80% of rated thermal power. On February 14, 1994, a spent fuel pool cleanup project anticipated to last several months was started.

At the conclusion of the report period, the 'D' main steam line remained isolated, limiting reactor power to less than 80%. The licensee was preparing for a forced outage to troubleshoot and repair the inoperable MSIV.

2.0 PLANT OPERATIONS (71707, 40500, 71714, 90701)

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
Reactor Building
Diesel Generator Building
Switchgear Rooms
Security Facilities
Fence Line
 (Protected Area)
Turbine Building
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. Control room and shift manning were in accordance with Technical Specification requirements. Posting and control of radiation, contamination, and high radiation areas were appropriate. Workers complied with radiation work permits and appropriately used required personnel monitoring devices.

Plant housekeeping, including the control of flammable and other hazardous materials, was observed. Generally housekeeping was acceptable, however on one occasion the inspector noted debris from a completed testing evolution and separately, a length of rope was observed to be suspended from an electrical conduit in the 'A' residual heat removal system valve room. The licensee acted promptly to correct these deficiencies. During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication of equipment status. These records included various operating logs, turnover sheets, tagout, and lifted lead and jumper logs.

2.2 **Response to Intake Canal Ice Floats**

On February 11, 1994, during routine outside tours, an operator noticed ice floats from Cape Cod Bay as well as freed ice buildup from the breakwater drifting into the intake canal and toward the intake structure. The operator notified the watch engineer who, in conjunction with operations section management, directed that reactor power be reduced and a main condenser backwash be conducted to dissipate the ice in the intake canal.

The inspector responded to the intake structure and observed portions of the backwashing evolution. Sluice gate position, direction of travelling screen rotation, and circulating and service pump status were verified to be correct. Additionally, control room operators maintained good communications with outside operators during the evolution. The backwashing quickly dissipated the ice floats. As a precautionary measure to reduce the potential for ice float accumulation, maintenance personnel temporarily placed a submersible pump into the intake structure (outside of the travelling screens) to maintain a turbulent flow environment.

The inspector concluded that the outside operator alertly identified and promptly reported the accumulation of the drifting ice floats. The watch engineer responded by initiating a backwash evolution that was well coordinated. The placement of a submersible pump in the intake structure to maintain a turbulent environment was a good initiative in light of an approaching storm front. The inspector had no further questions regarding this activity.

2.3 Storm Preparations

A winter storm, with predictions of heavy snowfall and moderate sea and wind conditions, was forecast to begin on the afternoon of February 11, 1994. The inspector observed licensee actions to prepare for the storm with emphasis on measures taken to improve intake structure capabilities. Operations section Standing Order #94-03 issued on February 8, 1994, directed actions be taken in advance of approaching winter storms. Specifically, the standing order addresses: (1) travelling screen operation and spare parts availability; (2) positioning of fire hoses to enhance screen wash capacity;, (3) briefing of intake structure alarm response procedures; (4) emergency and plant information computer screen dedication to sea water bay level trending; (5) intake structure manning; and, (6) switchyard monitoring. Additionally, the order directs a dedicated operator briefing for manual recirculation pump speed changes if the associated motor generator set scoop tube is in the locked up condition.

The standing order effectively addressed situations encountered during the December 13, 1993 coastal storm. The inspector toured the intake structure and verified the actions directed in the order had been accomplished. Additionally, the inspector attended the February 11, 1994, afternoon shift turnover and concluded shift supervision properly delegated operator responsibilities and described operator response priorities during the storm.

2.4 Main Steam Isolation Valve Inoperability

On February 17, 1994, reactor power was decreased to approximately 75% in order to return the 'A' recirculation pump motor generator (M-G) set speed control to the normal remote manual station in the control room. The M-G set scoop tube had been in the locked-up control position since December 16, 1993, when two unanticipated M-G set speed transients were experienced. Troubleshooting ultimately identified a failed resistance potentiometer on a scoop tube positioner amplifier circuit card. The transfer of M-G set speed control was completed satisfactorily.

The licensee took the opportunity during the reactor power reduction to accomplish the Technical Specification (TS 4.7.A.2.b.1.b.2) required quarterly fast full closure test of the eight main steam isolation valves (MSIVs). The full closure test is accomplished in accordance with station procedure 8.7.4.4 which requires each valve to close within 3.0 to 5.0 seconds. Seven of the eight MSIVs passed the test satisfactorily. However, the 'D' main steam line inboard MSIV, AO-203-1D, failed to close on the initial test attempt from its hand control switch. Operators returned the control switch to the open position, then cycled the switch to the closed position a second time and again the valve did not close. Operators then depressed the MSIV slow close push button and the valve stroked to the closed position. Subsequently, the MSIV was reopened, and closed by control switch actuation in approximately 4.1 seconds. The valve was maintained in the closed position and declared inoperable. Additionally, as required by Technical Specifications (TS 3.7.A.2.b), the 'D' main steam line outboard MSIV (AO-203-2D) was closed.

Technical Specifications permit continued operation indefinitely in this limiting configuration, however, reactor power is limited to approximately 75-80% of rated thermal power with a main steam line isolated.

At the conclusion of the inspection report period, the licensee was readying its forced outage planning and scheduling in anticipation of a shutdown to troubleshoot and repair the cause(s) for the MSIV surveillance test failure. In the interim, appropriate Technical Specification requirements were fulfilled and the 'D' main steam line was properly controlled in an isolated condition.

3.0 MAINTENANCE AND SURVEILLANCE (61726, 62703, 71710, 90712)

3.1 Automatic Depressurization System Declared Inoperable

On February 4, 1994, at 10:00 pm, the 'A' division actuation logic for the automatic depressurization system (ADS) failed during performance of surveillance procedure 8.M.2-2.10.9.1, "ADS Logic with Reactor Other Than Shutdown." Technicians stopped the surveillance and initiated a priority one maintenance request. The licensee declared ADS inoperable and notified the NRC in accordance with 10 CFR 50.72. Technical Specifications 3.2.B and 3.5.E require the reactor to be shutdown within 24 hours if ADS remains inoperable. Troubleshooting determined that the 'A' division two minute time delay relay (2E-K24A) had failed. A replacement relay was bench tested, installed, and successfully retested following installation. The licensee declared ADS operable at 2:00 am, on February 5, 1994. Close coordination between maintenance technicians and operations personnel effectively minimized the period of time that ADS was inoperable. Technicians successfully completed the balance of procedure 8.M.2-2.10.9.1, and verified that the 'B' actuation logic division remained operable throughout the event. The inspector reviewed the maintenance work plan and determined that troubleshooting had been properly implemented with appropriate detail, quality control hold points established, and post work acceptance criteria clearly specified.

The inspector independently reviewed electrical schematics and confirmed that the 'B' ADS actuation logic division was unaffected by the failure of relay 2E-K24A. The 'B' division provides fully redundant ADS actuation logic signals. All four ADS valves would have received automatic control signals to open if plant conditions warranted ADS actuation.

The licensee initiated problem report 94-9051 to determine the cause of the relay failure. Both divisions of ADS actuation logic contain the same model time delay relay. An improved relay was installed in both divisions during the last refueling outage in response to a vendor recommendation intended to eliminate excessive time delay drift. The problem report evaluation was in progress at the end of this report period. Dependent upon the results of the failure causal analysis, the licensee would evaluate the use of this model relay in other safety-related applications at Pilgrim Station. The inspector will assess resolution of this issue during routine inspection of the problem report process.

3.2 Failed Emergency Diesel Generator Turbo Air Assist Solenoid

On January 22, 1994, at 10:16 am, the 'B' emergency diesel generator (EDG) failed to achieve rated speed upon receipt of a start signal within the required time (11.62 seconds versus a required 10.25 seconds) during a routine surveillance. The EDG was declared inoperable and a priority one maintenance request was initiated. Maintenance personnel and system engineers developed a troubleshooting plan. Technicians inspected the starting air solenoid valves, turbo assist air solenoid valves, fuel supply rack booster air piston, and verified the continuity of the electrical start signals. The EDG has two turbo assist air start solenoid valves in a parallel configuration. The valves open on receipt of an EDG start signal to provide an additional supply of intake air to the diesel engine turbo-charger to minimize the 'turbo-lag' inherent in turbo-charged engines, which in turn improves engine starting times. Technicians disassembled the turbo assist solenoid valves and verified there was no damage to the internal components. However, the buildup of a fine amount of corrosion products and moisture was identified within the valves. The technicians concluded that the corrosion residue was sufficient to prevent the internal piston disk of each solenoid from developing the force necessary to open the solenoid by overcoming the internal piston closure spring force.

Technicians thoroughly cleaned the solenoid valves, and reassembled and reinstalled them. Procedure 8.9.1, "EDG Surveillance" was successfully performed as a post maintenance test and the EDG was declared operable at 1:30 am, on January 23. Excellent coordination between system engineers, operations, and maintenance personnel minimized the duration of EDG unavailability.

The inspector discussed the root cause and corrective actions with system engineers following the event. The solenoid valves are currently disassembled, inspected, and cleaned once per refueling cycle as a preventive maintenance (PM) activity. Material records did not indicate a history of repeat failures. At the conclusion of the report period, system engineers were in the process of developing an in-service functional test to be performed on a quarterly interval that would demonstrate the operability of each solenoid individually. Additionally, a modification is in development that would add manual isolation valves upstream of each solenoid to facilitate online maintenance of a solenoid without disabling the EDG. The source of the film residue remains under review, however it is believed to be the result of moisture in the turbo boost air system. The inspector determined that the licensee had initiated appropriate corrective actions to minimize probability of recurrence.

3.3 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 operation, and correct system restoration following testing. The following activities were observed:

- On January 12, 1994, the 'A' emergency diesel generator (EDG) monthly operability surveillance was satisfactorily completed in accordance with procedure 8.9.1, "Emergency Diesel Generator (EDG)." System engineers coordinated closely with operators to measure EDG room ventilation flow. This data was used to support the EDG operability assessment under varied ventilation lineups.

- On January 25, 1994, the "B" standby liquid control (SLC) pump seal was repacked with an improved material to eliminate loss of sodium pentaborate solution. Procedure 8.4.1, "SLC Pump Operability and Flow Rate Test" was satisfactorily performed as a post-maintenance test. Operators established good communications and properly resolved discrepancies observed during the inservice inspection testing portion of the surveillance.

- On February 2, 1994, Procedure 8.5.4.1-1, "High Pressure Coolant Injection (HPCI) Simulated Automatic Actuation, Flow Rate, and Cold Quickstart Test" was satisfactorily performed. This once per cycle surveillance demonstrates the ability of the HPCI system to start and achieve rated flow upon receipt of an automatic initiation signal. A prerequisite of this test is that the auxiliary oil pump, which provides control oil to the turbine control valve, has not been run for at least 72 hours prior to the surveillance. This surveillance had been initiated in December, but was prematurely terminated when the performing operator manually secured the HPCI turbine following receipt of an unanticipated turbine trip alarm (refer to NRC Inspection Report 50-293/93-23).

  The Nuclear Operations Supervisor (NOS) conducted an excellent pre-evolution briefing. Operators demonstrated strong knowledge of the procedure and system response throughout the surveillance. The inspector observed close oversight by quality control personnel during the lifting and relanding of control logic leads by instrumentation and control technicians. The inspector noted that the acceptance criteria section of the procedure did not specify the maximum permissible time (90 seconds) for the system to achieve rated flow. The NOS stated that the 90 second time limit is specified in the body of the procedure, and that he would not accept the procedure results if this time limit was not satisfied. This time limit is listed in the acceptance criteria for procedure 8.5.4.1, "HPCI System Pump and Valve Monthly/Quarterly Operability." The licensee takes credit for completion of the quarterly pump operability surveillance when the cold quickstart test is performed. Operations personnel properly resolved this minor procedure discrepancy.

- On February 3, 1994, Procedure 8.5.5.6, "Reactor Core Isolation Cooling (RCIC) Pump and Valve Operability from Alternate Shutdown Panel" was performed. This surveillance is conducted once per refueling cycle to verify the ability to start and operate the RCIC system from outside of the control room. System engineers attended the pre-evolution briefing and contributed meaningful historical information which helped operators to more fully understand the infrequently performed evolution. Communications and supervisor oversight during the surveillance were excellent.

  Valves were properly repositioned and the RCIC turbine was started from the alternate shutdown panel (ASP). The procedure requires design flow of 400 gallons per minute (gpm) to be established in manual control and then stable speed control to be demonstrated in automatic control. Operators established the design flow rate, but could not stabilize flow control. Pump flow oscillated in a 100 gpm band. System engineers and two senior reactor operators observed RCIC performance. Operators performed procedure 8.5.5.1, "RCIC Pump Operability Flow Rate and Valve Test at Approximately 1000 psig" to demonstrate that the RCIC system remained operable from the control room. Compensatory fire watch inspections of the cable spreading room and the alternate shutdown panel areas were promptly completed as required by Technical Specifications.

  Technicians developed a plan to troubleshoot the ASP flow control problem. Turbine control oil inspection and electrical circuit troubleshooting were completed with no discrepancies identified. The ASP flow controller received minor fine tuning during a bench calibration and was reinstalled. On February, 11, 1994, additional test monitoring equipment was connected to monitor flow control signals and procedure 8.5.5.6 was reperformed from the alternate shutdown panel. The test was successful with no discrepancies. Test leads were removed, the surveillance was again performed successfully, and RCIC was declared operable from the alternate shutdown panel. Although RCIC functioned as designed, troubleshooting did not conclusively identify the cause of the flow control failure. Problem report 94.9049 remains open pending final identification and resolution of the cause. In the interim, the licensee has increased the frequency of procedure 8.5.5.6 to provide additional assurance of reliability. The inspector determined that the licensee action to assess and correct the faulty flow control problem from the alternate shutdown panel was appropriate.

  The inspector had two questions concerning procedure 8.5.5.6. The control room would not be accessible during an event which would require alternate shutdown panel control of the RCIC system. Procedure 2.1.143, "Shutdown from Outside Control Room" directs operators to start both the HPCI and RCIC gland seal vacuum pumps locally. The inspector questioned why procedure 8.5.5.6 directed operators to start the RCIC vacuum pump from the control room instead of starting the pump locally. Currently, no periodic surveillance or maintenance activity verifies that the two vacuum pumps will start locally. The licensee stated that vacuum pumps were not required for continued operation of either the HPCI or RCIC systems. Without the vacuum pumps, gland seal steam leakage and non-condensible gases would escape to the surrounding machinery spaces which are located within the secondary containment boundary. However, HPCI and RCIC flow would be unaffected by the absence of the vacuum pumps. The inspector noted that the licensee's evaluation did not address equipment performance in the elevated room temperature and in the humid operating environment that would result from the steam leakage. The inspector also noted that while procedure 8.5.5.6 required a rated flow of 400 gpm, the procedure did not verify that the flow controller could establish rated system flow against full reactor pressure. The licensee initiated actions to revise the procedure to require the vacuum pump to be started locally, will be evaluating flow controller performance throughout the range of anticipated reactor pressure conditions during remote RCIC operation. The inspector determined that licensee actions were appropriate and had no further questions.

4.0 ENGINEERING (37828, 71707, 92700, 92701)

4.1 NRC Information Notice 93-101: Jet Pump Hold-Down Beam Failure

Jet pumps direct and accelerate cooling water flow from the downcomer annulus to the lower reactor vessel plenum. From the lower plenum, cooling water is directed upward across the fuel assemblies and subsequently generates steam. Jet pump failure could cause damage to other safety-related components within the reactor vessel and could adversely affect core water level recovery following a loss of coolant accident. Hold-down beam cracking and subsequent jet pump failure observed in 1980 was previously discussed in NRC Bulletin 80-07, "BWR Jet Pump Assembly Failure." Licensees were requested to perform specific inspections and implement corrective actions as appropriate.

In September 1993, a BWR in the United States experienced a jet pump failure which caused oscillating reactor vessel water level indications and a low water level scram. Subsequent inspection determined that this failure was unlike the 1980 occurrence in that the hold-down beam failed in the transition area between the main body of the beam and the beam end. NRC Information Notice (IN) 93-101 and vendor service information letter (SIL) 065 "Jet Pump Beam Cracking", were issued to inform the industry of the event, subsequent inspection findings, and recommended actions. The vendor noted that current ultrasonic testing (UT) procedures do not address cracking in beam end locations and revised test methods are being developed. Vendor analysis identified the failure mechanism to be intergranular stress corrosion cracking (IGSCC) and determined that crack growth to failure could occur within an operating cycle. Original design jet pump beams, fabricated using the "Equalized and Aged" heat treatment process, are susceptible to IGSCC. The vendor recommended that all original design jet pump beam assemblies (part number 137C5238 G001) with accumulated service of more than eight years of service be replaced at the next refueling outage. The vendor recommendation does not apply to an improved design of jet pump beam assemblies (part number 137C5238 G002), or to original design beam assemblies manufactured with reduced preload using the High Temperature Annealing (HTA) process, which are less susceptible to IGSCC.

The licensee researched material history records and determined that the original jet pump beams were replaced during refueling outage No. 6 (1983/1984). All jet pump beams currently installed at Pilgrim station underwent the HTA manufacturing process. Therefore, the licensee concluded that near term IGSCC failure is not credible, and that SIL 065 does not apply. The inspector independently reviewed material records and design documents. Those records indicate that Pilgrim Station has HTA-processed, original design jet pump hold-down beam assemblies (part number 137C5238 G001) installed. These assemblies may contain either an original sized beam or an improved (thicker) beam which has further reduced susceptibility to IGSCC.

Vendor documen ded in 1981 to support selection and installation of the HTA processed beams, state that the ...vice life of these beams is in excess of forty years. These documents further state that a jet pump beam inspection is not needed during this service life. The licensee evaluated material characteristics of the new beams and conservatively determined that an inspection should be performed after twenty years of service. The inspector questioned whether the existing hold-down beam ins ction plan remained valid following the new information discussed in SIL 065 and NRC I 1. In response to this concern, engineers reopened their operating experience review of IN 93-101. Operating experience action item (OEAI) 93.9015 was established to verify the correct inspection schedule.

Subsequent licensee conversations with the vendor and review of the guidance in NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure" indicate that the new beam assemblies should be inspected sooner than previously recommended. Initial discussions ranged from acceleration of the inspection schedule (refueling outage No. 10, 11, or 12) to consideration of jet pump bea lacement. Final resolution of the jet pump beam assembly inspection schedule was in pro ss and tracked as OEAI 93.9015 at the close of this report period. The inspector concluded that the potential IGSCC failure mechanism discussed in NRC IN 93-101 does not apparently pertain to the Pilgrim Station jet pump hold-down beams, and that the licensee has taken appropriate actions to reevaluate the planned inspection schedule.

4.2 Pressure Locking of Motor Operated Valves (NUREG-1275)

Pressure locking and thermal binding as discussed in NRC NUREG-1275 "Operating Experience Feedback Report - Pressure Locking and Thermal Binding of Gate Valves", have caused several safety related valves to become inoperable throughout the industry. Operational experience indicates double disk and flexible wedge gate valves can become pressure locked by being placed in operating configurations which subject them to high pressure fluids in the valve bonnet. A high differential pressure may then develop from the bonnet to the high and low pressure sides of the valve. This may result from a rapid depressurization event or from the convection heating of water which may have become trapped inside the bonnet due to seat leakage. This high differential pressure creates a force that opposes valve disk movement from the seat. Generically, this additional force was not considered when establishing design specifications for the valve actuators. Thermal binding can occur during plant cool downs if the valve body of a flexible wedge gate has a greater coefficient of expansion and contraction than the valve disk. If this occurs, the valve disk experiences compressive forces in the valve seat. Consequently, when the valve is closed hot and allowed to cool, the difference in thermal contraction can cause the seats to bind tightly, causing the valve to become difficult or impossible to reopen until the valve reaches an operational thermal equilibrium.

The licensee recently developed specific criteria to assess the susceptibility of various safety-related motor operated valves (MOV) to pressure locking and thermal binding. Initial evaluation identified thirty-two MOVs which warranted a detailed assessment. The inspector noted that the assessment criteria, for both normal operating and accident modes, were consistent with the guidance of NUREG-1275. The MOVs were prioritized for evaluation according to the existing MOV Betterment Program schedule. Three of the first six MOVs evaluated were determined to be susceptible to either pressure locking or thermal binding.

The inspector attended a planning meeting for MOV program work to be accomplished during the next midcycle maintenance outage (MCO) scheduled for November 1994. The schedule includes modification of the three susceptible MOVs. A wide range of modification options were discussed. Proposed modifications included installation of a bonnet tap to the high pressure piping upstream of the valve, drilling a weepage hole in the upstream side of the valve disk, installation of compensating spring packs, and replacement with an alternate disk design. Engineering, Maintenance, and Planning personnel are working closely to efficiently incorporate hardware modifications into the existing MCO schedule. The licensee has also been in contact with other utilities and industry work groups to better understand the failure mechanisms and to evaluate potential solutions. The inspector concluded that the licensee was actively establishing a program consistent with NUREG-1275, to identify and correct MOV pressure locking and thermal binding problems. Engineering personnel have developed a good understanding of the issue. The inspector had no further questions regarding this issue and will continue to provide routine assessment of the licensee MOV program performance.

5.0 PLANT SUPPORT (71707)

5.1 Radiological Posting of High Radiation Areas

During routine plant tours of the process buildings, the inspector observed radiological postings to be comprehensive and clearly posted. Several radiological problem reports (RPRs) had recently been initiated concerning identification of new high radiation areas (HRA) during periodic radiological surveys. The inspector discussed the reports with the Radiological Section Manager, who has in turn encouraged technicians to submit RPRs whenever additional HRAs are identified. Through this process, various plant evolutions and maintenance conditions had been identified and incorporated into survey practices. A recently issued Radiological Section standing order directed that plant areas subject to dose rate variations be posted as HRAs at 75 percent of the regulatory limit. Radiological technicians also conducted prompt assessments of alarming dosimeter setpoints and work activity history in the vicinity of newly identified HRAs to ensure station radiological practices had been complied with. The inspector concluded that radiological survey practices were proactive, HRAs were properly posted, and reportablity evaluations were appropriate.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (40500)

6.1 Licensee Event Report Review

The inspectors reviewed Licensee Event Reports (LERs) 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 events warranted further onsite followup. The LERs were also reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022 and its supplements.

- **LER 94-01**

LER 94-01, High Pressure Coolant Injection (HPCI) System Inoperable Due to Unplanned Isolation During Surveillance Testing, dated February 3, 1994, describes the January 4, 1994, HPCI primary containment isolation system Group IV actuation during analog trip system calibration testing. This event was summarized in NRC Inspection Report 50-293/93-23, Section 1.0.

An event critique was conducted immediately after the HPCI system was restored to normal standby status. Initially, licensee troubleshooting identified minor voltage spiking (3-5 volts) as the potential cause of the isolation when the calibration knob was depressed at the calibration unit of the analog test panel. However, several attempts to recreate the isolation signal were unsuccessful. Additionally, this potential cause would not have accounted for a six second delay time that was observed between the insertion of the test signal and the receipt of the isolation. A second potential cause that similarly could not be reproduced would have been the malfunction of one of the two normally deenergized isolation logic relays that are in a series circuit configuration. The final potential cause, considered most probable, was that the performing technicians incorrectly checked continuity across the logic relay not in test. This practice caused both relays to energize, completing the isolation logic, and causing the isolation to occur. This scenario would also account for the six second time delay as technicians landed the test instrument across the relay, contact points. The calibration unit and the isolation logic relay whose malfunction could have caused the isolation were replaced as precautionary measures since a definitive root cause could not be determined. Additionally, calibration procedures are being reviewed to ensure proper circuit continuity checks.

The inspector reviewed a preliminary copy of the event critique report, portions of the associated problem report (PR 94.9004) response, discussed the logic circuitry with the cognizant system engineer and Instrumentation & Control supervisor, and independently reviewed applicable logic diagrams. The licensee conducted a thorough evaluation of this event, identified each potential cause, and initiated appropriate corrective actions. This LER also properly addressed the reporting criteria.

6.2 Offsite Review Committee

On February 8, 1994, the Nuclear Safety Review and Audit Committee (NSRAC) was convened for the first meeting of the 1994 calendar year. Several changes in the NSRAC composition and structure have occurred since the last meeting. Initially, Mr. H. Hukill resigned as the NSRAC Chairman and Mr. M. Miles resigned as a committee member and the Radiological and Emergency Preparedness Subcommittee Chairman. Mr. J.E. Howard, an existing committee member was appointed as the new NSRAC Chairman. Mr. L. Waldinger, of the Monticello Nuclear Generating Plant was appointed as a new committee member. Additionally, the NSRAC subcommittee structure was consolidated from five standing subcommittees to four. The standing subcommittee that conducted reviews of safety evaluations prior to full committee discussion was eliminated. This subcommittee had been established originally in response to the volume of safety evaluations generated during implementation of performance improvement programs following the issuance of NRC Confirmation of Action Letter (CAL) 86-10, and its supplements. The volume of safety evaluations has decreased since closure of NRC CAL 86-10, and its supplements. The general NSRAC continues to review all safety evaluations. Finally, the committee is scheduled to convene four times during the 1994 calendar year. The committee had convened six times per year in recent years since issuance of the NRC CAL. Technical Specification 6.5.B that governs NSRAC function requires that the committee meet at a frequency of at least once per six months.

The inspector attended portions of the NSRAC meeting on February 8th and observed plant staff presentations for operations, licensing, emergency preparedness, and regulatory affairs. The presenters were well prepared and exhibited good knowledge of the subject matter. The committee was attentive, and demonstrated an objective questioning attitude. The committee effectively winnowed out the potential safety and regulatory aspects of the discussions. Additionally, the Chairman ensured an open forum for technical discussion while maintaining overall committee focus. The inspector had no concerns regarding the conduct of the NSRAC meeting.

7.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (30702)

7.1 Routine Meetings

At periodic intervals during this inspection, meetings were held with senior BECo plant management to discuss licensee activities and areas of concern to the inspectors. At the conclusion of the reporting period, the resident inspector staff conducted an exit meeting on March 2, summarizing the preliminary findings of this inspection. No proprietary information was identified as being included in the report.

7.2 Management Meetings

On February 17, 1994, NRC Licensee Meeting Number 94-27 was convened in the NRC Region I office to discuss the BECo motor operated valve (MOV) program. The NRC staff had identified several areas of concern during an NRC inspection of the MOV program that was conducted at Pilgrim Station the week of December 13-17, 1994. The meeting was a continuation of the inspection process. Conclusions from the meeting and the inspection will be documented in NRC Inspection Report 50-293/93-22.

7.3 Other NRC Activities

On January 19-21, 1994, an NRC Region I systems specialist conducted a follow-up inspection of previously unresolved NRC inspection items. Inspection results will be documented in NRC Inspection Report 50-293/94-05.

On January 19-25, 1994, an NRC Region I materials specialist conducted an inspection of the licensee cyclic fatigue evaluation program. Inspection results will be documented in NRC Inspection Report 50-293/94-01.

On January 31 to February 4, 1994, an NRC Region I radiological protection specialist conducted an inspection of the licensee radiological controls program. Inspection results will be documented in NRC Inspection Report 50-293/94-03.