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DETAILS

1.0 Summary of Facility Activities

The plant was shut down on April 12, 1986 for an unscheduled maintenance outage. Subsequently, the NRC issued Confirmatory Action Letter 86-10 which required that the licensee seek approval from the NRC Regional Administrator for reactor restart. The outage continued throughout the current inspection period.

On May 16, 1986, plant operators, maintenance workers, and clerical staff went on strike. Laborers for the major contractor on site, Bechtel also went on strike during the inspection period. Neither strike had been settled by the end of the inspection period.

2.0 Followup on Previous Inspection Findings (Differential Relay Problem)

(Closed) Unresolved Item (86-07-03). Failed Diesel Generator Lockout Relay. On April 26, 1986, the licensee experienced failures of the A diesel generator differential and lockout relays. The function of the differential relay is to provide generator protection against phase-to-phase or phase-to-ground faults by energizing the lockout relay if such a condition is sensed. When energized, the lockout relay trips open the generator breaker and mechanically locks in the tripped state until manually reset. As the lockout relay reaches full locked out position, its relay coil is deenergized. On April 26, 1986, one of the three coils associated with the differential relay failed, causing an erroneous signal to be generated. The lockout relay energized but did not operate to the full locked out position. Due to the incomplete actuation the lockout relay coil remained energized. The continuously energized coil failed, resulting in a small fire. The licensee rebuilt, tested, and reinstalled the lockout relay. Equipment history indicates no similar lockout relay problems. Corrective action taken regarding the differential relay was to electrically bypass the failed component, leaving the unaffected "A" coils and the "B" diesel generator differential relay intact.

During review of the incident, the inspector noted that the differential relay in question was a General Electric Model 12CFD relay. IE Information Notice 85-82, issued October 18, 1985, identifies this model relay as being not seismically qualified. When questioned regarding the continued use of the unqualified relay in an active safety related application the licensee provided the inspector with Engineering Service Request (ESR) Response Memorandum NED-85-788 dated July 23, 1985. The ESR had been initiated in response to industry information concerning this problem. NED-85-788 confirms that the differential relays installed at PNPS are not seismically qualified and will require replacement. It also contains a "Justification for Continued Operation" which briefly addresses the impact of spurious relay operation on three scenarios: Seismic Event with a LOCA, Loss of Offsite Power with a LOCA, and Seismic Event with Loss of Offsite Power. This JCO was not reviewed by onsite or offsite safety review committees. Two of the discussed scenarios require timely if not immediate operator action to reset the resulting generator breaker trips. Operator action in these instances entails recognition of the problem by the control room staff and dispatching an operator to a remote location to clear the condition. The inspector also reviewed PNPS Procedure 5.2.1, Revision 7, Earthquake. While the procedure does direct the operator to check the electrical buses for spurious trips, it does not provide any specific guidance and also requires the operator to perform numerous parallel tasks. No operator training or procedure enhancements had been implemented to highlight the potential problem area.

One scenario assumes a seismic event coincident with a loss of offsite power. Under these conditions, a spurious operation of these relays results in a total loss of station AC power; a condition not analyzed in the safety analysis. In any event the reliability of the emergency diesel generators is lessened by the presence of unqualified components. Prior to identification of these concerns by the inspector, the licensee had no scheduled plans for replacement of these relays.

This item is considered unresolved and will be the subject of further review (86-14-01).

The inspector discussed this matter with Nuclear Engineering Department and station management. The inspector was informed that a Failure and Malfunction Report and Potential Condition Adverse to Quality Report had been initiated to track the component deviation. An evaluation will be performed to determine the ramifications of operating with the unqualified components. The inspector will review the type and content of any evaluation performed. Engineering is conducting a review of ESR dispositions during the preceding year to identify any similar circumstances. In addition, it was stated that engineering department personnel have received training regarding proper implementation of the corrective action program.

Nuclear Operations Department and Engineering Department management stated that the relays in question would be replaced with seismically qualified components prior to startup. In the interim on shift operations personnel have been trained regarding the possible problems associated with the current condition.

Based on issuance of the above unresolved item, this item is closed.

(Closed) Unresolved Item (293/85-06-03). Core spray recirculation test valve, MO 1400-4A, operator mounting bolts found loose. This item was last updated in inspection report 85-08. During a routine tour, on April 26, 1986, operations personnel identified two broken operator mounting capscrews on the 1400-4A valve. Corrective actions taken by the licensee in response to this recurring problem were reviewed by the inspector, and are discussed in section 4 of this report. Design changes implemented appear to be adequate. Periodic inspections by both operations and maintenance personnel will identify any additional problems. The inspector had no further questions. This item is closed.

(Closed) Unresolved Item (293/86-07-04). Review of corrective action for failed cap screws on core spray valve MO 1400-4A. Licensee corrective actions dealing with the above problem are discussed in detail in section 4 of this report, and under item 85-06-03. Based on the changes described, and on the licensee's commitment to continue periodic inspection of the valve, this item is closed.

(Open) Violation (86-01-08) Failure to follow procedures for completing a post trip review and failure to log disabled control room annunciators. The inspector reviewed the licensee response letter, dated April 11, 1986. In the letter, the licensee indicated that an evaluation of control room equipment problems would be conducted and the resident inspector informed of the results of the evaluation by May 11, 1986. However, at the end of the inspection period, the licensee had not completed these actions. The inspector discussed the commitment with the Plant Manager, who indicated that he would check on the status of the evaluation and inform the resident inspector of the results. This item will remain open, pending further NRC review of licensee actions in this area.

(Closed) Follow Item (86-06-10). Review resolution of audit findings for QA audits 84-34 and 85-25, including Deficiency Report 1466. This NRC open item highlighted DR 1466, a QA audit finding concerning high pressure coolant injection (HPCI) system testing. On May 16, 1986, the recently appointed Plant Manager asked the inspector about DR 1466. The Plant Manager indicated that he had been asked to review the DR by senior licensee management. This DR was issued by QA on November 8, 1985 and had been contested by the Nuclear Operations Department since that time. The new Plant Manager promptly determined that he agreed with the QA finding. The licensee notified the NRC of the HPCI surveillance test problem later that day. This DR and the audit findings are discussed further in section 7 of this report. This item will be administratively closed. Further NRC followup will be conducted in response to the violation in section 7.

3.0 Routine Periodic Inspections

a. Daily Inspection

During routine facility tours, the following were checked: manning, access control, adherence to procedures and limiting conditions for operation (LCO's), instrumentation and recorder traces, control room annunciators, safety equipment operability, control room logs and other licensee documentation.

No unacceptable conditions were identified.

b. Systems Alignment Inspection

Operating confirmation was made of selected piping system trains. Major motor operated and manual valve positions for safety equipment were verified during routine checks of the control room. Valve power supply, breaker alignment, and safety equipment controller set points were also checked.

No items for further inspection were identified and no unacceptable conditions noted.

c. Biweekly Inspections

During plant tours, the inspector observed shift turnovers and checked: plant conditions, valve positioning and locking (where required), instrumentation lineup, radiological controls, security, safety, and general adherence to regulatory requirements. Plant housekeeping and cleanliness were evaluated. The inspector had no further questions.

d. Plant Maintenance

The inspector observed and reviewed maintenance and problem investigation activities to verify compliance with regulations, administrative and maintenance procedures, codes and standards, proper QA/QC involvement, safety tag use, equipment alignment, jumper use, personnel qualifications, radiological controls for worker protection, fire protection, retest requirements, and reportability per Technical Specifications.

-- Cracked MSIV Return Springs at Fermi-2

During the inspection period it was reported that four return springs in two of the Fermi Unit 2 MSIV's were found to be broken. The vendor for the Fermi Unit 2 MSIV's is Atwood-Morrell. The supplier of the springs in question is Duer Spring and Manufacturing Company. A part 21 notification is presently being evaluated by the utility staff. The MSIV's installed at Pilgrim are also manufactured by Atwood-Morrell. In addition cracking of the pilot poppet return springs has been identified. The inspector discussed with licensee maintenance personnel the event at Fermi Unit 2, its relevance to Pilgrim and plans for addressing the potential problem. The licensee had not responded to the inspector's questions by the end of this report period. This issue will be examined in a future inspection (86-14-02).

-- Refueling Bridge Replacement: Heavy Load Handling Procedures

During the inspection period the licensee transported the components necessary for replacement of the existing refueling bridge from an outside laydown area to the refueling floor. Components were transported from the laydown area into the reactor building truck lock at elevation 23', rigged for lifting, and hoisted up through the equipment hatch to elevation 117' using the reactor building crane. The inspector reviewed Plant Design Change number 86-58, Refueling Bridge Replacement, to verify that proper precautions, procedures, inspections and safe load paths had been established. The inspector also examined Pilgrim Nuclear Power Station Procedure 3.M.1.4, General Maintenance Procedure for Heavy Load Handling Operations, to determine if lifts planned under PDC 86-58 were in accordance with station policy. In addition, completed lift sign off sheets were examined. Operations appear to have been well planned and in accordance with the established heavy load handling program. The inspector had no further questions.

-- Review of Station Salt Service Water Pump Maintenance History

During the report period the licensee experienced varying problems with three of the station salt service water (SSW) pumps. The D pump was rebuilt due to excessive vibration and low discharge pressure. The E pump also demonstrated high vibration. A fault developed in the C pump motor and the motor was subsequently rewound. The inspector reviewed past inservice testing results for the service water pumps and determined that while the recent coincident problems appear significant, individual pump histories do not indicate accelerated pump wear. The inspector will evaluate any future SSW pump problems and inservice test data during routine inspections.

e. Surveillance Testing

The inspector observed parts of tests to assess performance in accordance with approved procedures and LCO's, test results (if completed), removal and restoration of equipment, and deficiency review and resolution.

On May 15, 1985 at 11:00 p.m., the inspector noted an I&C test instrument in the control room with an expired calibration sticker. The instrument was a Hewlett-Packard timer-counter, no. 135 that was last calibrated on October 18, 1985. The calibration due date on the instrument was April 18, 1986. The licensee later indicated that the instrument had only been used for the calibration of channel one of the main stack gas radiation monitor. The monitor was subsequently recalibrated. The plant was in cold shutdown at the time of the incident.

The inspector reviewed I&C instrument issue records and discussed the counter with I&C personnel. The following problems were noted during this review:

-- Procedure 1.3.36, "Measurement and Test Equipment", section D.1, states that measuring and test equipment storage areas shall provide sufficient separation of ready-to-use equipment (calibrated and limited use) from other equipment (rejected) as to preclude inadvertent use. Contrary to this requirement, test equipment with expired calibrations were not promptly separated from other equipment. Issuance records indicated that instruments with expired calibrations were left in the instrument lockers for several weeks to three months in one case. The records indicated that a second timer-counter, no. 134, was used with an expired calibration on March 13, 1986. This instrument was not removed from the instrument locker until two weeks after the calibration due date.

-- The I&C equipment issuance policy is verbal and not always followed. The policy, according to I&C management, requires that instruments be signed out using an instrument issuance sheet. This was not consistently done. For example, the timer-counter in the control room on May 15 had not been signed out. Also, calibration due dates were not recorded on the sheets as required, in many cases.

-- The I&C personnel did not have confidence that all test equipment was included on the preventative maintenance (PM) data base. This data base is used to identify equipment coming due for calibration so that the equipment can be removed from the equipment lockers.

As immediate corrective action, the licensee agreed to check equipment records to ensure that the instruments without due date entries on the equipment issuance sheets were in calibration. The timer-counter in the control room was removed and will be calibrated. The timer-counter that was used in March with an expired calibration has since been checked and was found to be in calibration.

An additional test instrument with an expired calibration was used by personnel in the Onsite Safety and Performance Group to check a local leak rate cart on May 23, 1986. This instrument, a Fluke Multimeter no. S8600A, was last calibrated on October 28, 1985 and was due for calibration on April 28, 1986. The instrument is maintained by the Onsite Safety and Performance Group.

The multimeter was not entered in the PM data base. The inspector also noted that the multimeter serial number and calibration due date were not required to be recorded on LLRT test data sheets.

The licensee stated that the instrument was only used during the test witnessed by the inspector. A second multimeter was obtained and the LLRT cart checks repeated. No discrepancies were found.

10 CFR 50 Appendix B, criterion XII, requires that measures be established to assure that measuring and testing devices used in activities affecting quality are properly controlled. Failure to ensure that test equipment is only used within its calibration period is a violation of 10 CFR 50 (86-14-03). A previous citation in this area was issued in 1985 (NRC Inspection Report 50-293/85-03).

4.0 Review of Plant Events

a. RHR Minimum Flow Protection Logic Design Deficiencies

On May 19, 1986, the licensee reported that a situation had been identified where a single instrument failure could lead to loss of all four RHR pumps. During review of IE Information Notice 85-94 the licensee discovered that a failure of either differential pressure switch 1001-79A or 1001-79B would cause both system minimum flow valves to remain closed on pump start. If the RHR minimum flow valves failed to function while all other system discharge valves were closed, pump damage would occur in 20 to 60 seconds. These conditions would exist during a LPCI initiation with the reactor vessel at pressures greater than 400 psig; during a small break LOCA. The loss of all RHR functions including LPCI, drywell spray, torus cooling and shutdown cooling represents a loss of safety functions beyond the plant design basis.

IE Compliance Bulletin Number 86-01 was issued to all GE boiling water reactors on May 23, 1986 addressing the problem identified by Boston Edison. This bulletin requires licensees to take prompt corrective action and to provide the NRC with written information detailing problem resolutions.

Boston Edison has submitted to NRC:Region I written notification of noncompliance as required by 10 CFR Part 21. The inspector will review the corrective actions taken by the licensee and any written responses required by Bulletin 86-01 during the next inspection period (86-14-04).

b. Loss of Safety Related 480V AC Motor Control Center B-10

Safety related 480V AC Bus B-6 feeds 480V AC motor control center B-10 through breaker B603. MCC B-10 in turn powers the C Salt Service Water (SSW) pump through breaker 1061. On May 12, 1986, while attempting to start the C Salt Service Water pump, breaker B603 tripped open resulting in the deenergization of 480V MCC B-10. The C SSW pump motor breaker, breaker 1061, did not act to protect MCC B-10. Subsequent action taken by the licensee included testing of breaker 1061 and B603. Problems with the performance of the time delay trip function for two phases of the B603 breaker were discovered. This breaker was replaced with a tested spare and shipped to General Electric for repairs. Testing of the C SSW pump motor identified no problems.

On May 23, 1986 during start of C SSW pump installed spare breaker B603 again tripped, resulting in a second loss of MCC B-10. Licensee investigation revealed a fault in the C SSW pump motor. Preliminary testing indicates that both breaker B603 and 1061 are functioning properly.

Licensee investigation and evaluation is progressing under Failure and Malfunction Reports 86-115 and 86-123. This evaluation should address the failure of component breaker 1061 to protect MCC B-10 and the failure of breaker B603 time delay trip devices to perform as designed. The inspector will review corrective actions taken during a future inspection (86-14-05).

c. Broken Cap Screws on MO-1400-4A Motor Operator

On April 26, 1986 during an inspection of the 1400-4A valve the licensee identified two sheared valve yoke to adapter plate capscrews. Instances of loose or broken yoke to adapter plant capscrews were documented in LERs 83-010, 83-035 and in inspection report 85-06. Previous efforts to alleviate the problem, including increased capscrew installation torque, lockwire, and use of thread locking compound have been ineffective. In response to the latest problem recurrance the licensee performed a detailed review of the valve design, examination of the failed capscrews, and conducted testing to determine the contribution of system vibration to the failure.

Review of the valve history indicates that MO-1400-4A was originally a motor operated globe valve. The globe valve was replaced with a gate valve and the existing operator retained. The bolt pattern of the operator was matched to the new gate valve yoke by installation of an adapter plate. The adapter plate was fastened to the yoke and the operator by a number of capscrews. It was determined that the current operator torque switch settings, originally specified for the globe valve application, are excessively high for use with the installed gate valve. Performance testing revealed valve closing thrust approximately 10,000 lbs. greater than that required to drive the valve. It was also determined that the high capscrew installation torque produced preload stresses contributing to the problem. Licensee analysis of piping vibration data concluded that while vibration levels were not excessive they were a contributor to the observed failures. The sum of the above contributors is believed to constitute the problem root cause.

The inspector reviewed approved Plant Design Change (PDC) 86-32, ESR Response Memorandum NED 86-411, and discussed these planned corrective actions with responsible personnel. Changes specified by these documents include: 1) use of high strength capscrews, 2) reduction of capscrew installation torque, 3) reduction of operator torque switch settings to valves consistent with the design, and 4) placement of a segmented fillet weld between the valve yoke and adapter plate. Licensee engineering staff believe that the problem root causes have been identified, and adequately addressed by the above described changes. In light of the recurring nature of these problems periodic inspections of the valves seem prudent. Station operations staff has in the past performed daily inspections of the valves. One of the inspections had identified the most recent failure. The operations department has committed to continue the daily inspections, and to formally add the checks to the operator's daily tour list. Based on review of the modifications and continued inspections of the applicable valves the inspector considers the issue resolved.

d. Operators, Maintenance Workers, and Clerical Workers Strike

On May 15, 1986 at midnight, plant operators, maintenance workers, and clerical workers went on strike. The inspector observed the plant turnover from the striking workers to management. No problems were identified. This item is discussed further in section 9 of this report.

e. Loose RPS Wiring

On May 2, 1986, the licensee found a loose wire connecting a relay in the reactor protection system (5A-K18A) to the common ground bus. On May 5, 1986, a loose ground wire caused relay 5A-K9A to deenergize generating a half scram. The licensee subsequently determined that the compression couplings which connect the individual relay ground wires to the ground bus were too large, which prevented the couplings from gripping the ground wiring tightly.

At the management meeting with NRC Region I on May 12, 1986, the licensee agreed to discuss their evaluation of the loose wiring in a supplemental response to CAL 86-10. This item will be reviewed further during followup to the CAL response (86-14-06).

5.0 Observations of Physical Security

Checks were made to determine whether security conditions met regulatory requirements, the physical security plan, and approved procedures. Those checks included security staffing, protected and vital areas barriers, personnel identification, access control, badging, and compensatory measures when required. No problems were identified.

6.0 Radiation Protection

Radiological controls were observed on a routine basis during the reporting period. Standard industry radiological work practices, conformance to radiological control procedures and 10 CFR Part 20 requirements were observed. Independent surveys of radiological boundaries and random surveys of nonradiological points throughout the facility were taken by the inspector. The following problems were noted.

a. Under-Responding Alarming Dosimeter

On May 9, 1986, the inspector learned that an integrating alarming dosimeter had underresponded during use in a 70 R/hr radiation field. Specifically, a Dositec model DOS-502A had been used during work on a radioactive resin liner on April 30, 1986. Following the work, the licensee noted that radiation dose recorded by the alarming dosimeter, 290 mR, did not agree with the individuals thermoluminsecent dosimeter (TLD) reading, 518 mR.

The worker had been in a radiation field as high as 70 R/hr during the work on the liner. The licensee stated that monitoring by health physics personnel, rather than the alarming dosimeter, was the primary method to limit the worker's radiation dose. The alarming dosimeter vendor subsequently told the licensee that the dosimeter response to radiation was not linear above about 9 R/hr. However, the vendor literature did not indicate this dose rate limitation.

The inspector informed Radiation Specialists in NRC Region I of the problem with the alarming dosimeter response. The adequacy of radiological controls during work in the 70 R/hr field on April 30 will be reviewed during a future specialist inspection.

b. Radiation Survey at Edgar Station

On May 16, 1986, NRC Region I received an allegation that radioactive material was being stored at Edgar Station, a decommissioned coal-fired power plant owned by the licensee. The licensee indicated that non-radioactive material used at Pilgrim was stored at the fossil station. This material included decontaminated staging stored in four large shipping containers.

On May 21, 1986, the inspector observed a radiation survey of stored material at the fossil station, including portions of the staging and material stored in an adjacent building. The licensee surveyed the material using an Eberline E140 instrument with an HP-210 pancake G.M. radiation probe. Checks for loose contamination were also performed. The inspector noted that the survey was conducted in a slow, careful manner by licensee personnel.

Two items associated with the staging, a staging coupling and an empty barrel, were found to have fixed radioactivity levels slightly above background. Both had activity levels of 50 to 100 counts per minute above background. These levels are below the licensee's limits for releasing material from the site, i.e., 0.1 mr/hr fixed activity or about 600 counts per minute on the survey instruments. No loose radioactivity was detected on the two items.

The inspector had nc further questions concerning material stored at Edgar Station. However, the inspector noted that the survey instrument conversion factor for converting instrument count rate to radiation exposure levels was not included in station procedures. The licensee stated that the conversion factor (600 counts per minute corresponds to 0.1 mR/hr) was derived from experience with radiation fields in the plant, but not documented. The licensee agreed to evaluate and document the conversion factors. The inspector had no further questions.

7.0 Quality Assurance Audit Review

The inspector reviewed two licensee audits (84-34 and 85-25) which examined licensee programs for compliance with certain technical specification requirements. Several deficiencies were identified during the audits and subsequently documented in deficiency reports (DR). The following problems were noted with DR 1466.

DR 1466 (Audit 85-25) was issued on November 8, 1985. The DR identified six high pressure coolant injection (HPCI) system valves that were not adequately tested during simulated automatic initiation testing. Specifically, the DR identified sections of electrical wiring for the valves that were not checked during HPCI surveillance testing. The DR was discussed between QA and the Nuclear Operations Department (NOD) for three months. The NOD argued that the valve wiring could be maintained intact through plant configuration control and did not need to be tested in the surveillance program. The QA Department rejected this approach to surveillance testing. Poor plant configuration control in the mid 1970's was recently blamed for an undetected wiring change that made a plant electrical safety bus inoperable (Licensee Event Report 86-03 and NRC inspection 50-293/86-06).

The rejected DR 1466 response was listed in weekly DR status reports to senior corporate management during January 1985. The DR was listed as overdue in the status reports after the 90-day corrective action period expired on February 6, 1986. No Vice President extension was requested for the DR.

The Nuclear Engineering Department subsequently issued a memo agreeing with the QA interpretation on April 18, 1986. The QA Manager issued a memo to the Vice President, Nuclear, on April 23, 1986 which requested his assistance in resolving DR 1466. On May 16, 1986, the NOD agreed with the DR finding and reported the inadequate surveillance test to the NRC via the ENS telephone system.

Criterion XVI in 10 CFR 50 Appendix B requires in part that measures be established to assure that conditions adverse to quality are promptly corrected. Failure to conduct a full simulated automatic initiation test of the HPCI system as required by technical specification 4.5.C.1 is a condition adverse to quality. Failure to correct this deficiency for more than six months after the problem had been identified in DR 1466 is a violation of Criterion XVI in 10 CFR 50 Appendix B (86-14-07).

The following programmatic problems were also noted during the review of QA audits 84-34 and 85-25. These problems may have contributed to the lack of a timely response to DR 1466.

-- Section 18.4.5 of the Boston Edison Quality Assurance Manual (BEQAM) requires that deficiency reports be dispositioned within 90 days of issuance or must have a DR extension authorized by the appropriate Vice President. Contrary to the requirement, DR's routinely exceed either the 90-day limit or the VP extension dates for long periods of time without resolution. For example, a licensee DR status report dated March 28, 1986, showed that eleven DR's had overdue corrective actions; with some overdue by as much as twelve to fifteen weeks. Another DR status report dated May 9, 1986, indicated that seven DR's were overdue; some by as much as 18 weeks. Overdue DR's are either beyond the initial 90-day period or beyond the VP extension date.

   A contributing factor to the late DR's was the practice of not always requesting VP extensions. For example, DR's 1456 and 1466 were both passed their initial 90-day completion dates by at least 12 weeks at the time of the May 9 status report. However, VP extensions were not requested for either DR.

-- Section 18 4.6 of the BEQAM requires that a written request for a second response be forwarded to the appropriate Vice President if QA can not obtain a satisfactory resolution of a DR. However, the QA Department routinely forwards requests for second responses to Department Managers rather than the Vice Presidents. As discussed above, DR 1466 was not referred by QA to the appropriate Vice President until after two DR responses had been rejected, over five months after the DR was issued. Although they are not sent the requests for the second DR responses, senior corporate management is sent weekly DR status reports that highlight overdue DR's and rejected DR responses.

-- Section 16.2.6 of the BEQAM defines "significant" as conditions that indicate lack of or reduction of management's ability to control activities affecting quality. In addition, Section 16.2.9 of the BEQAM states that conditions reportable to the NRC under 10 CFR 50.72 and 50.73 are significant. Department Managers are required by the BEQAM to respond to a significant finding within one week.

However, deficiency reports involving inadequate surveillance testing were not classified by QA as "significant". For example, DR 1321 (Audit 84-34) indicated that simulated automatic actuation tests were not adequately conducted for the reactor core isolation cooling (RCIC), core spray, low pressure coolant injection (LPCI), and automatic depressurization (ADS) emergency cooling systems. A similar finding was made in DR 1466 (Audit 85-25) concerning the HPCI system. Neither finding was classified as significant. DR 1321 was not resolved for nine months. DR 1466 was resolved after six months of review and was eventually reported to the NRC under 10 CFR 50.72 as a technical specification violation.

-- A nonagressive surveillance testing philosophy is evident in the NOD responses to the QA findings. For example, DR 1322 noted that the RCIC flow rate test at 150 psig was not adequate because a test potentiometer rather than the RCIC flow controller was used during the test. The NOD disputed this finding for three months before finally agreeing to change the RCIC test. The response to DR 1466 is another example of the limited surveillance philosophy. Also, the licensee's response to NRC surveillance findings (NRC report 50-293/85-03) was limited.

As corrective action for these problems, the HPCI surveillance procedures have been modified and the wiring in question will be tested prior to declaring HPCI operable during the next reactor startup. The revised HPCI procedure was not reviewed during the inspection period, but will be reviewed during the followup to the citation in this section. Contractors are reviewing the licensee's surveillance testing program for completeness and technical adequacy. The results of this review will be evaluated during a future NRC inspection. The licensee has indicated that to identify and resolve QA problems more quickly, daily meetings will be held between QA representatives and the Plant Manager. In addition, the BEQAM will be modified to require that disputed DR's be escalated to a Vice President 45 days after issue; further escalated to the Senior Vice President in an additional 15 days; and finally escalated to the President 75 days after issue.

Lack of aggressive action on QA findings has been previously noted. Citations were issued in NRC inspection report 50-293/85-03 for failing to promptly correct a surveillance testing problem involving reactor protection system alarms and for failing to take prompt corrective actions for other QA findings. In addition, the lack of timeliness in correcting QA/QC findings was highlighted as a program weakness in the surveillance testing section and in the overall summary section of the 1985 NRC SALP report.

8.0 Followup to Confirmatory Action Letter 86-10

Confirmatory Action Letter (CAL) 86-10 was issued on April 12, 1986. The letter contained concerns in three areas: spurious group one primary containment isolation closures, the inability to open the outboard main steam line isolation valves (MSIV) following the isolations, and primary coolant leakage into the residual heat removal (RHR) system.

The inspectors observed portions of the following maintenance activities: (1) replacement of the reactor mode switch, (2) reassembly of two MSIV pilot poppets and one MSIV main poppet, (3) installation of the GETARS computer system, and (4) disassembly and inspection of MO-1001-28B RHR injection valve. A local leakage test of the MSIV's in the "B" main steam line was also observed and is discussed in section 3.e of this report. In addition, the inspectors reviewed training conducted for management personnel who installed the SB-9 replacement mode switch and documentation related to the various work activities.

The following problems were noted:

-- On May 10, 1986, the inspector observed set screw installation during the assembly of the 1C MSIV pilot poppet in the hot machine shop. The inspector verified that torque wrenches used during the assembly were calibrated and set properly. The work was controlled by plant design change (PDC) 86-28. A QC inspector was present during the assembly.

The inspector noted that the workers generally followed set screw installation instructions. However, the workers did not drill and tap the set screw holes in the pilot poppet in the order specified in the instructions. The inspector noted that QC witness points in the procedure could be affected by deviating from the specified procedure sequence. The licensee indicated that the procedure would be changed to more closely match the work and to clarify the QC witness points. In addition, the workers were instructed to follow the procedure sequence. The licensee also indicated that the other MSIV's had been assembled in the sequence required by the original set screw procedure. The inspector had no further questions on this item.

-- On May 10, 1986, the inspector observed that workers removing the reactor mode switch were not closely following the verification steps in the procedure. Specifically, the workers signing a verification step in the procedure were not always witnessing the entire step. The licensee subsequently instructed the workers to witness each step in its entirety prior to signing the procedure. The steps in question were repeated. The inspector subsequently noted that workers were more careful with the verification steps. No further problems were identified.

-- On May 20, 1986, the inspector witnessed final disassembly and initial inspection of RHR injection valve MO-1001-28B. Activities observed appeared well planned, and adequate safety precautions had been established. The licensee conducted and documented inspection of the valve internals upon disassembly. The inspector also examined seating surfaces and valve internals. While no significant seating surface degradation was identified, erosion/corrosion of the valve poppet body was noted. This erosion/corrosion was documented and forwarded to engineering for evaluation. Engineering disposition indicates that continued use of the concerned poppet for up to five years is acceptable, however a recommendation for replacement during the next refueling outage has been made. The licensee also plans to disassemble and inspect the MO-1001-28A valve for similar conditions. The inspector had no further questions.

Periodically during the report period the inspector witnessed activities associated with the installation of the GETARS monitoring system. The inspector also reviewed temporary modification number 86-18 detailing the installation of GETARS and its impact on the plant. Based on the information presented in the temporary modification package it appears that no credible failure mode exists which could compromise the independence or operability of the primary containment isolation and reactor protection system channels. The inspector observed that installation activities were conducted in accordance with the applicable instructions. The inspector also discussed with the licensee the planned training for on-shift personnel addressing operation of the GETARS system. The inspector had no further questions.

The inspectors will continue to follow the actions taken in response to CAL 86-10 and document this follow up in future inspections.

9.0 Strike Activities

On May 15, 1986, plant operators, maintenance workers, and clerical staff went on strike. Operations Department supervisors (licensed senior reactor operators) were shifted to licensed operator positions at midnight on May 15. The inspector observed the shift turnover at midnight and toured the facility. No discrepancies were noted, other than a test instrument with an expired calibration (section 3.e of this report). During the remainder of the inspection period, the inspectors periodically observed supervisors in licensed operator roles. No problems were identified.

The licensee had prepared for the strike by stockpiling food and bedding material onsite. Plant storage tanks were checked and topped off prior to the strike deadline. Local officials were informed of the possible labor action. Police officers were stationed at the entrances to the owner controlled areas at the plant to assist the onsite guard force. No disturbances occurred during the inspection period.

The licensee discussed operator staffing with the inspector prior to the strike. Three operating shifts were established and manned by management personnel. Only Operations Department supervisors who had been on watch just prior to the strike were assigned to the licensed operator positions. Licensed personnel in staff positions were assigned to act as unlicensed operators during the strike.

Training plans for the acting licensed and unlicensed operators were discussed in an NRC management meeting in Region I on May 19, 1986. Additional discussions were held between Operator Examiners in Region I and the licensee on May 21, 1986. During these discussions, the licensee agreed to furnish additional details in a written response to Region I. The inspector had no further questions at this time.

All nonessential plant activities were cancelled for two days after the start of the strike to allow supervisory personnel time to adjust to the reduced staffing size. The inspectors will continue to review plant activities to ensure that the strike is not adversely affecting plant safety.

In an unrelated labor dispute, laborers working for the chief contractor onsite, Bechtel, went on strike on May 1, 1986. The strike did not significantly affect operational activities at the plant. Construction work involving some plant modifications were suspended due to the strike.

10.0 Review of LER's

LER's submitted to NRC:RI were reviewed to verify that the details were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted onsite followup. The following LER's were reviewed:

LER No.	Event Date	Report Date	Subject
86-009-00	4/11/86	5/9/86	In series primary containment isolation valves MO-1001-28B and 29B indicating leakage past seats
86-010-00	4/15/86	5/15/86	Main Steam Line Isolation while reactor shutdown
86-011-00	4/19/86	5/19/86	Leakage past MSIV's in excess of LLRT criteria

The event described in LER 86-09 was reviewed and documented in inspection report 86-07, licensee response to Confirmatory Action (CAL) 86-10, and section 8 of this report. Events documented in LER 86-10, as well as several similar isolations, were reviewed by NRC Augmented Inspection Team during inspection 86-17 and were addressed by the licensee in the response to CAL 86-10. The MSIV problems described in LER 86-11 and the corrective actions taken by the licensee are included in the licensee's response to CAL 86-10, and are summarized in section 8 of this report.

11.0 Management Meetings

At periodic intervals during the course of the inspection period, meetings were held with senior facility management to discuss the inspection scope and preliminary findings of the resident inspector. No written material was given to the licensee that was not previously available to the public.

On May 19, 1986 a meeting between Region I and Boston Edison senior management was conducted at Region I offices in King of Prussia. Purpose of the meeting was to discuss Boston Edison's response to Confirmatory Action Letter 86-10, future plans regarding pertinent issues and to resolve or identify any CAL 86-10 outstanding issues.

Attachment 1 to Inspection Report 50-293/86-14

Persons Contacted

L. Oxsen, Vice President, Nuclear Operations
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D. Swanson, Nuclear Engineering Department Manager
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T. Sowdon, Radiological Section Head
J. Seery, Technical Section Head
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S. Wollman, On-Site Safety and Performance Group Leader
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R. Sherry, Chief Maintenance Engineer
D. Mills, Construction Management Group Leader
J. McEachern, Resource Protection and Control Group Leader
E. Graham, Compliance and Administrative Group Leader