U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.:	50-293
Report No.:	93-23
Licensee:	Boston Edison Company 800 Boylston Street Boston, Massachusetts 02199
Facility:	Pilgrim Nuclear Power Station
Location:	Plymouth, Massachusetts
Dates:	December 7, 1993 - January 17, 1994
Inspectors:	J. Macdonald, Senior Resident Inspector A. Cerne, Resident Inspector D. Kern, Resident Inspector L. Kay, Reactor Engineer, Region I, DRS

Approved by: Eugene M. Kelly 2/4/94
E. Kelly, Chief
Reactor Projects Section 3A
Date

Scope: Resident safety inspections in the areas of plant operations, maintenance and surveillance, engineering, and plant support. Initiatives selected for inspection included the effectiveness of cold weather preparations and operating precautions, feedwater system leak repairs, and core spray isolation valve leakage.

Inspections were performed on backshifts during December 7, 23, 27-29 and January 4, 6, 7, 10-13, 1993. Deep backshift inspections were conducted on January 8 (11:00 am - 1:30 pm and 5:30 pm - 12:00 midnight), January 9 (00:01 - 1:30 am), and January 17 (1:30 - 10:20 pm).

Findings: Performance during this six week period is summarized in the Executive Summary. An unresolved item was identified in Section 2.2 concerning corrective actions for intake structure design and operation from the December 13, 1993 storm.

EXECUTIVE SUMMARY

Pilgrim Inspection Report 93-23

Plant Operations: The extreme sea conditions encountered during the December 13, 1993 storm presented significant challenge to plant operators and intake structure systems. Operators demonstrated excellent communications and coordination of actions in response to a decreasing sea water level condition in the east bays of the intake structure. These actions maintained the plant in a safe condition until normal sea water levels in the bays were restored. However, post-event review revealed that the actual duration and magnitude of the level reduction were not clearly recognized during the event (and not until 30 days after the event) due to alarm and instrumentation limitations. Continued BECo management attention to the review of this event is warranted to ensure a comprehensive causal analysis. Separately, operations personnel properly implemented cold weather preparation procedures prior to and during the recent period of sustained sub freezing conditions.

Maintenance and Surveillance: Maintenance, Engineering, and Operations personnel closely coordinated their activities to successfully repair a leaking feedwater system 3/4 inch globe valve which is part of the Class I pressure boundary. A safety evaluation was approved by the on-site Operations Review Committee and discussed with NRC management prior to implementation of the repair. The repair technique and sealant material were closely supervised and controlled. Periodic surveillances were properly performed without incident.

Engineering: Elevated core spray (CS) system piping temperature was symptomatic of backleakage upstream of a containment isolation valve. Operations, Maintenance, and Engineering personnel coordinated effectively to monitor and assess the effect of the leakage, which is sufficiently small such that both the CS and primary containment isolation systems remained operable. Licensee actions, including plans to continue trending CS piping pressure and temperature, demonstrated a sound safety perspective.

Safety Assessment/Quality Verification: Licensee event reports (LER) were comprehensive and accurately addressed all reporting criteria. The inspectors noted that the high quality and level of detail contained within the LERs has facilitated event assessment and root cause analysis.

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ATTACHMENTS

Attachment: BECo Slides, "Switchyard/HPCI/RCIC Improved Plans"

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

At the beginning of the report period, Pilgrim Nuclear Power Station (PNPS) was operating at approximately 100% of rated thermal power. On December 7, 1993, a full participation Emergency Preparedness Exercise was conducted. Officials from federal, state, and local governmental agencies participated in the exercise.

Reactor power was decreased on December 13 and again on December 16, 1993, in response to severe winter storm conditions and to perform backwashing of the main condenser. During the December 13, 1993 storm, the east bays in the intake structure experienced a decrease of approximately 15-18 feet in sea water level for a period of approximately 8 minutes due to fouling of the traveling screens. During the power reduction December 16, 1993, the "A" recirculation pump motor generator motor-generator (MG) set experienced a brief speed oscillation and a speed runback to minimum speed. Control room operators placed the MG set hydraulic scoop tube in the locked up position, and controlled MG set speed manipulations manually at the local control station. The reactor was returned to full power operations on December 17 after the weather subsided.

On January 4, 1994, a minor body-to-bonnet leak was identified on an isolation valve for a 3/4 inch drain line off the body of the "B" main feedwater line outboard check valve. A temporary leak sealant repair was successfully performed on the valve during a January 8-9, 1994, weekend power reduction. Also on January 4, 1994, the high pressure coolant injection system (HPCI) automatically isolated during surveillance testing due to a sensed low reactor vessel pressure condition. The isolation was reset and HPCI was returned to normal standby service early on January 5, 1994. The isolation was believed to be caused by a faulty test and calibration unit in the associated analog trip system cabinet. Inspector review of this event was continuing at the end of the report period.

The "A" MG set scoop tube remained in the locked up position and, with the exception of brief power reductions to accomplish control rod pattern exchanges, the reactor remained at 100% power through the conclusion of the inspection period.

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

Control room instruments were independently observed by NRC inspectors and found to be in correlation among 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 to be acceptable. 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, including various operating logs, turnover sheets, tagout, and lifted lead and jumper logs, were found acceptable.

2.2 Intake Structure Response to Severe Winter Storm

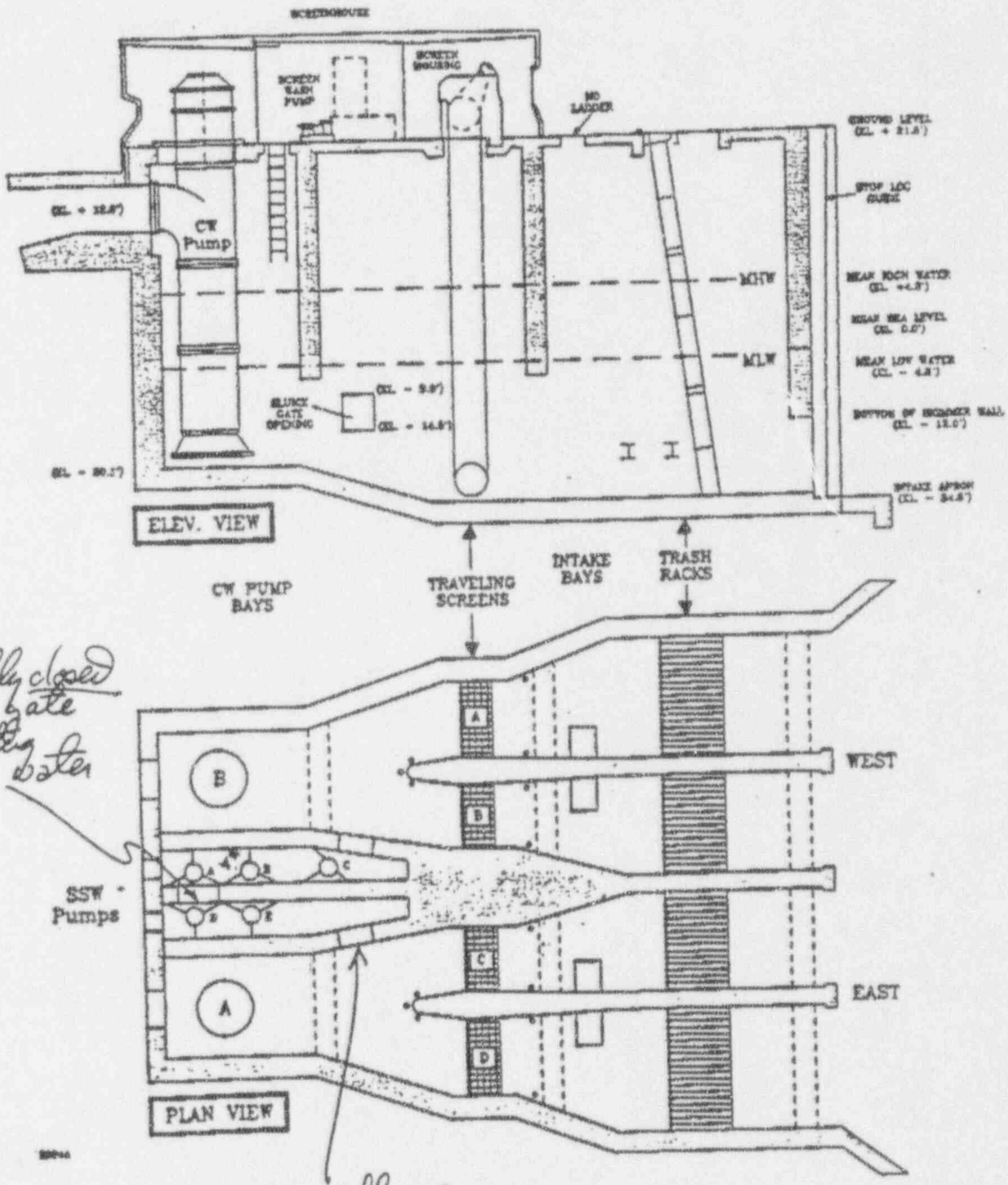
2.2.1 Intake Structure Design

The intake structure is a steel-reinforced concrete structure. It houses the salt service water (SSW) system pumps, the sea water (or circulating) pumps, the electric and diesel fire pumps, travelling screens and screen wash pumps, trash racks, log stops, and the chlorination control systems. The portion of the intake structure that houses the SSW pumps is considered a Class I structure. All elevations in the structure are referenced to a zero value of the normal mean sea level. The intake structure is divided into four bays, the east SSW and sea water bays and the west SSW and sea water bays. The SSW and sea water bays communicate via a 3 x 5 foot (ft.) sluice gate with a minimum elevation of -14.5 ft. These openings are the normal supply path for water from each sea water bay into the SSW pump bay. The east and west SSW bays are normally isolated, but can communicate via a normally closed 3 x 5 ft. rear gate with a minimum elevation of -19 ft. The intake structure bottom is at -20 ft. 2 inches (in.) elevation in the bays. Seaweed and debris are removed from the incoming Cape Cod Bay sea water as it flows across the log stops, trash racks, and through the four travelling screens prior to entering the intake structure water bays. The "A" and "B" travelling screens service the west intake bays and the "C" and "D" screens service the east intake bays. Intake structure water level indication in the main control room includes: (a) high travelling screen differential pressure alarms set at 6.6 psig; (b) SSW bay low level alarms set at -7 ft. (alarm for each bay); and (c) level indication for each sea water bay. Refer to the following section drawing from BECo operating procedures for plan and elevation views of the Pilgrim screenhouse.

ATTACHMENT 9
Sheet 1 of 1

SCREENHOUSE DRAWING SECTION

normally closed
sluice gate
connecting
service water
bays



normally open
sluice gate
connecting sea and
service water bays

2.2.2 Storm Chronology and Response

On December 13, 1993, coastal Southeastern Massachusetts experienced a severe winter storm. During the storm, high winds and heavy seas carried seaweed and debris into the plant intake canal and up to the intake structure. At approximately 9:04 am, reactor power was in the process of being decreased to maintain main condenser vacuum and to prepare for condenser backwash evolutions to reduce fouling. The four intake structure travelling screens were in continuous operation. High differential pressure alarms, indicative of increasing fouling, were received on the "C" and "D" travelling screens. Operators were dispatched to the intake structure and observed the "C" and "D" screens to be heavily fouled and experiencing mechanical failures in the form of broken shear pins and deformed screen baskets. The "B" travelling screen was briefly secured, while the "A" screen continued to operate. Additionally, the "A" sea water (circulation) pump motor operating current increased from approximately 155 amperes to 175-185 amperes and remained fairly constant. Additionally, the east salt service water bay low water level alarm (- 7 ft) annunciated and a decreasing water level in the east sea water bay was indicated by control room level instrumentation (LI-3831A, control room panel C-1).

The nuclear watch engineer (NWE) and system engineer, who had previously responded to the intake structure, visually observed a decreased water level in the east salt service water bay when compared to the west bay. This indicated that the fouling of the "C" and "D" travelling screens was of sufficient magnitude to reduce ocean water flow into the east bays of the intake structure. At approximately 9:17 am, the NWE manually opened the normally closed rear gate separating the SSW bays, which provided direct communication (and flow of water) between the east and west SSW bays. At 9:30 am, the NWE, recognizing that level had not fully recovered and that the "C" and "D" travelling screens remained fouled, directed the control room to secure the "A" sea water pump. These actions quickly restored normal intake bay levels. Securing the "A" sea water pump (155,500 gpm) also served to decrease the differential pressure across the "C" and "D" travelling screens, allowing debris to be cleared.

At 9:33 am, operations and maintenance personnel cleared the debris sufficiently to return the "B" and "D" screens to service. Reactor power had been reduced to approximately 60% by 9:40 am. The "C" screen was then started, but was stopped within two minutes due to continued storm-related deficiencies. By 9:53 am, control rods had been inserted below the 80% load line and reactor power was at approximately 46%.

By 10:20 am, reactor power was reduced to and maintained at approximately 35% . Condenser backwashing was performed sequentially through the waterboxes and was completed at 2:40 pm through the "B" sea water pump and at 4:42 pm through the "A" sea water pump.

2.2.3 **Event Followup**

Problem Report (PR) 93.9510 was issued to document the travelling screen and intake structure problems encountered during the storm. The plant recovered from the storm and the reactor was returned to full power on December 14, 1993. Maintenance personnel replaced 11 of the 54 screen baskets on both the "C" and "D" travelling screens, and two baskets on the "B" screen. The licensee initiated corrective actions within the scope of the problem report process. Operator performance, procedure adequacy, procedure implementation, equipment and instrumentation design are under review. The evaluation was still in progress at the end of the inspection report period, and PR 93.9510 remained open. However, several preliminary conclusions were developed by the licensee. Initially, the normal tide and storm surge created a +6 to +8 ft. intake structure level. Data retrieved from the emergency and plant information computer (EPIC) indicated that at approximately 9:05 am, seaweed fouling of the "C" and "D" screens was of sufficient severity to cause a decreasing water level in the east bays. Level continued to decrease until approximately 9:17 am, when the rear gate in the SSW bays was opened, cross connecting the east and west bays. Normal east bay levels were not restored until the "A" sea water pump was secured at 9:30 am. Additionally, EPIC data indicates east sea water bay water level decreased by 15 to 18 ft. before the rear gate was opened and the "A" sea water pump was secured. The EPIC data recorded the minimum water level in the east sea water bay at approximately -12 ft.

The inspector independently reviewed control room logs, EPIC data, alarm response procedures, applicable system operating procedures, and intake structure drawings. Additionally, the inspector discussed the event with involved licensed operators, the responsible system engineer, and maintenance and operations section management. The inspector determined the control room alarm response procedures and referenced system operating procedures were adequate. The inspector concluded operations personnel responded promptly and effectively to the indications of a decreasing water level condition in the east bays. The NWE and system engineer provided excellent supervisory and technical presence in the intake structure and initiated proper direction to restore water level. Control room supervisors and operators demonstrated good crew coordination that ensured the "A" sea water pump was promptly secured, the circulating water system flowpaths were properly realigned, and reactor power was reduced in a controlled manner.

However, the inspector concluded that operators were not aware of the actual duration or magnitude of the decreasing level in the east bays during the event as was indicated by post-event review of the EPIC data. Due to the existing high tide conditions and the rate at which the east bay level was decreasing, the inspector estimated a minimum of nine minutes would have elapsed from the initiation of the decreasing level until the east SSW bay low level alarm setpoint of - 7 ft. would have been reached. Additionally, because the SSW rear gate was being opened at that time, the inspector also estimated the alarm condition would have cleared within a maximum of eight minutes. Control room operators indicated the alarm was intermittently present for a significantly less time period. Surging seas may have contributed to the intermittent nature of the alarm. Additionally, the alarm instrumentation appeared to have been damaged and rendered nonfunctional when impacted by the in-rush of sea water when the rear gate was opened. The rear gate has since been maintained open (through the end of this report period) in order to provide SSW bay alarm indication for either bay via the west bay level alarm, and while the east SSW bay level instrumentation is being repaired.

The inspector expressed concern that routine plant operation with the rear gate open and the SSW bays in communication may be in conflict with the system safety design basis as described in the Final Safety Analysis Report (FSAR). Specifically, FSAR Section 10.7.6, states the SSW system is designed with sufficient redundancy so that no single active system component failure could prevent the system from achieving its safety objective. The section further states two independent closed loops of SSW, with full heat transfer capability on each loop, are provided. The FSAR does not address rear gate operation. Clearly, opening the rear gate to mitigate a potentially significant loss of SSW bay water level in accordance with properly evaluated procedures would be acceptable. However, it also would appear that operation with nonredundant (manual) cross-tieing the SSW bays would create an open system versus closed loop configuration, and the open rear gate therefore introduces a single active failure vulnerability. This concern remains under review by BECo licensing personnel.

2.2.4 **Industry Experience Review**

On July 2, 1992, the NRC issued Information Notice (IN) 92-49, "Recent Loss or Severe Degradation of Service Water Systems." The Notice discussed events in which service water system performance had been severely degraded at several facilities due to fouling of travelling screen systems or due to personnel error during off-normal evolutions involving the service water system. The Notice stated that recovery from such events strongly depends on human action, particularly with respect to following procedures and accurately communicating information.

The inspector reviewed the licensee's operating experience review program response to NRC IN 92-49. The Notice was issued to BECo system engineering (action item 92.0053, dated August 24, 1992). System engineering conducted a detailed review of the events referenced in the notice and documented existing intake structure improvements and recommended several others. Specifically, a trash rack rake (PDC85-80D) was installed that provided the capability to keep the stationary trash racks clear. Additionally, a travelling screen upgrade project was initiated (PDC85-80C) for the "C" and "D" screens during the 1993 refueling outage that included installation of stainless steel baskets, two-speed screen motors, and improvements to the level instrumentation that inputs into the screen differential pressure alarms. The "A" and "B" screens are scheduled to undergo the same modifications during the Fall 1994 midcycle outage. Finally, a significant modification was made involving a setpoint change (FRN 92-04-04) to the SSW bay low level alarm from -14 ft. to -7 ft. The review of IN 92-49 was completed and approved by the operating experience review coordinator on November 23, 1992. The inspector concluded the actions taken in response to NRC IN 92-49 were adequate, and properly considered the discussion in the notice.

2.2.5 Conclusions

The extreme sea conditions (i.e., storm tide, swells, debris) encountered during the December 13, 1993 storm presented significant challenge to plant operators and intake structure systems. Seaweed fouling caused extensive damage to the travelling screens which in turn caused a significant loss of level in the east water bays. Operators in the intake structure and in the control room exhibited clear communications and coordinated response actions well throughout the event. Those actions maintained the plant in a stable and safe condition until normal intake structure water level was restored. Operator performance was pivotal since, as was discussed in NRC IN 92-49, recovery from degraded service water system events depends strongly on human actions. Additionally, plant modifications were effectively evaluated by system engineering and implemented in response to previous similar industry events.

Notwithstanding the good performance noted above, the actual duration and magnitude of the decreasing water level condition in the east bays was not clearly recognized during the event. Further, it was not until approximately thirty days after the event and following heightened NRC inspector involvement that senior station management became fully aware of this information. To date, limited event causal analysis and corrective action recommendations have been accomplished through the problem report process. The operations and systems engineering personnel involved in the problem report response have generated good proposed actions to improve response procedure directions and travelling screen operation, to better cope with a similar potential future event. However, the licensee has utilized higher-level approaches (i.e., dedicated teams) in the past for such significant issues. Based upon the potential significance of this event and the unresolved nature of several issues raised, the inspector concluded additional licensee management attention is warranted. Specific technical concerns related to the reliability of the service water system and integrity of the intake structure and ultimate heat sink that should be addressed include: (1) the licensing basis for operation with the rear gate open, bypassing SSW bay separation; (2) the maximum differential pressure against which the rear gate can reasonably be expected to function reliably; (3) the adequacy of sea water pump operating current as an effective indication of intake bay level conditions throughout the anticipated ranges of ocean tides and main condenser performance; and, (4) the adequacy of the travelling screen high differential alarm setpoint. These issues and final event corrective action review are identified as an **unresolved item (50-293/93-23-01).**

2.3 Cold Weather Preparations and Operating Precautions

Outside temperatures at Pilgrim Station frequently drop to below freezing during the Winter months. During this reporting period, temperature approached zero degrees Fahrenheit (F) several times. Extremely cold temperatures have the potential to freeze fluid and pneumatic lines or otherwise adversely affect the operation of certain safety-related systems and other components considered important to station operation. The inspector reviewed procedure 8.C.40, "Cold Weather Surveillance" to determine the adequacy of the licensee's cold weather preparations and operations.

Silktemp to direct leakage toward floor drains and away from steam tunnel components. Additionally, a repair plan using Furmanite, a temporary leak sealant, was developed. Field Revision Notice (FRN) 94-03-02 was developed to control the injection of the sealant material.

Three repair options were included in the FRN. The primary and preferred option involved injecting sealant into the inlet port of the 200B valve to seal the seating surfaces and stop any further downstream leakage paths. This method was selected as the primary option by the licensee because it did not threaten the 200B body-to-bonnet pressure boundary interface and based upon experience, had the highest probability of success. Additionally, this repair option presented the lowest projected radiological dose exposure to involved personnel. The second repair option involved installing an injection adaptor at the body-to-bonnet interface on the 200B valve and directly injecting sealant into this area. The third option involved installing an injection adaptor on a downstream isolation valve (6-HO-201B) on the drain line, and attempting to inject sealant back through the drain line to the body-to-bonnet interface on the 200B valve.

Safety Evaluation

The FRN was supported by safety evaluation, SE 2797, that was reviewed and approved by the onsite review committee (ORC) on January 7, 1994. The evaluation addressed sealant chemical compatibility, maximum sealant volume to be authorized for each repair option, and potential sealant interaction with the reactor coolant system. The inspectors attended the ORC meeting and concluded the committee appropriately addressed the technical bases presented in the safety evaluation. Additionally, because the repair involved the modification of a Class I boundary component and recent industry experience indicated weakness in the control of temporary leak sealant injection processes, conference calls were conducted on January 6, 7, and 8, 1994 with BECo staff and NRC senior management and technical specialists. The conference calls ensured all technical information, safety evaluation bases, and intended licensee supervisory controls were delineated. The NRC did not, however, consider that there was commensurate focus upon the consequences of the potential complications or failures associated with each of the repair options. Rather, only after considerable NRC involvement did recent industry experience described in NRC Information Notice 93-90 receive licensee management attention.

Actual Repair

The repair was scheduled to be implemented during a January 8, 1994 planned power reduction to conduct main condenser backwashing. The inspector discussed control room preparations for the power reduction and repair with the nuclear watch engineer (NWE). The NWE had good knowledge of the repair plan and had dedicated an onshift senior reactor operator to be present at the repair briefings and to be stationed at the steam tunnel entrance to provide operational support as necessary.

Repair option 1 involved drilling a 5/16 inch (0.312 in.) hole to a depth of 5/16 in. into the inlet port of the 200B valve body. The valve inlet socket was schedule 160 stainless steel and assumed to have a wall thickness of approximately 0.375 in. The hole was to be tapped with a machine thread and an injection adapter was to be installed. After the adapter was installed, a 1/8 inch (0.125 in.) hole would be drilled through the remainder of the valve body and the drain line pipe (also schedule 160) and into the process flow. At that time, the injection gun would be attached to the adaptor and a maximum of five, one cubic inch sticks of sealant, would be injected sequentially at an injection pressure not to exceed 4,800 pounds per square inch (psi) until the leak stopped.

The maintenance department pre-briefing was thorough. Maintenance division management stressed adherence to the controls established by the FRN. Each repair option was completely reviewed. Management clearly stated that, should the option being attempted prove unsuccessful, the work effort would be stopped and evaluated prior to proceeding to the next option. The briefing also addressed potential difficulties that could be encountered during the repair activities. Specifically, the briefing addressed the potential to drill through the valve body during the initial 5/16 in. drill. This was a probable scenario due to the precision of depth control that would need to be accomplished by hand and using only nominal values in determining actual valve wall thicknesses. Being a socket joint, drilling directly through the valve body was not significant. The pressure boundary was established by the socket weld which was outside drill location and the drain line pipe in the socket would be anticipated to significantly reduce any leakage pressure. The Furmanite technicians stated their understanding of this concern and that it has been encountered routinely in the past. Radiological protection technicians conducted the radiation work permit (RWP 94-0067) briefing at the conclusion of the maintenance briefing. The briefing was thorough and addressed all concerns. Safety personnel similarly conducted an effective briefing.

The inspector was present in the steam tunnel for the duration of the repair effort. Several minor delays were encountered. Specifically, the air drill first taken into the work area did not function, which required a replacement to be located. Also, the 5/16 in. machine thread tap broke when cleaning the thread, which required a tap extruder to be used to remove the broken portion of the threaded hole. The only complication subsequently encountered involved the drilling of the initial 5/16 in. depth hole, which penetrated further than intended and through the valve body. The technicians responded to this occurrence, as briefed, and it presented no complication to completion of the repair. Ultimately, the leak was sealed by injection of a single stick (one cubic inch) of sealant at an injection pressure of approximately 3,500-3,900 psig.

Conclusions

The repair plan was well developed and properly evaluated. Pre-evolution briefings were thorough and stressed a controlled and deliberate approach. Supervisory oversight and presence were evident. The inspector had no concerns regarding this repair.

3.2 High Pressure Coolant Injection System Cold Start Test

On December 7, 1993, the licensee initiated prerequisites to conduct the high pressure coolant injection system (HPCI) cold start surveillance test procedure 8.5.4.1-1. However, approximately 15 seconds after the automatic initiation signal was input, control room operators received the HPCI turbine trip alarm and, in response, secured the system. Initial review of system performance as recorded by the emergency and plant information computer (EPIC) indicated a normal start sequence within all expected parameters. The routine monthly HPCI surveillance test (Procedure 8.5.4.1) was subsequently performed satisfactorily and the system was returned to a standby condition.

Continued system engineering evaluation concluded that the HPCI turbine trip alarm condition during the cold start test was a result of the alarm logic configuration, and therefore the system was functioning properly. Specifically, the alarm logic senses HPCI steam admission valve, HPCI-3, and HPCI control valve position. Both valves are normally closed in the standby condition. Upon receipt of a start signal, the steam admission valve close limit switch, LS-7, which indicates the valve is not full closed, energizes a 15 second time delay relay (23A-K18). The time delay relay is designed to provide sufficient time for the HPCI-3 valve and the turbine control valve to stroke to the full open position. The control valve open limit switch, LS-3, which indicates the control valve is in the full open position must be contacted prior to the completion of the 15 second time delay, or the HPCI turbine trip alarm (via relay 23A-K31) will be energized. A prerequisite of the cold start test procedure is that the HPCI auxiliary oil pump not be operated prior to receipt of the test initiation signal. Since the control valve opens on hydraulic oil pressure, the lack of initial pressure with the auxiliary oil pump not running until receipt of the start signal would delay the stroking of the control valve to the full open position. Data generated by the EPIC system indicated the control valve reached the full open position in approximately 19 seconds. Therefore, the alarm should be received 15 seconds after the start signal is initiated (and the HPCI-3 valve starts to open) and would be anticipated to be present for approximately four seconds (until the control valve strokes full open).

The inspector discussed this analysis in detail with the system engineer. Additionally, the associated HPCI procedures, EPIC data, alarm logic elementary wiring drawings M1J 16-10 and M1J 17-12 were independently reviewed. The inspector concurred with the licensee's causal analysis. Although the alarm has no operational impact, the licensee is evaluating one of two changes to preclude brief receipt of the alarm during normal system startup. One is to increase the HPCI-3 relay time delay to approximately 20 seconds. The second is to reconfigure the control valve relay to the close limit switch, such that logic would be satisfied as soon as the control valve begins its open stroke as opposed to when it reaches full open. The inspector concluded either option was viable in that the basic intent of the alarm would be maintained. The inspector had no further questions.

3.3 Routine Surveillance

The inspector observed portions of selected surveillance 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 activity was observed:

- The monthly emergency diesel generator operability surveillance was successfully completed on January 12, 1993 in accordance with procedure 8.9.1, "Emergency Diesel Generator (EDG)." System engineers coordinated closely with operators to measure

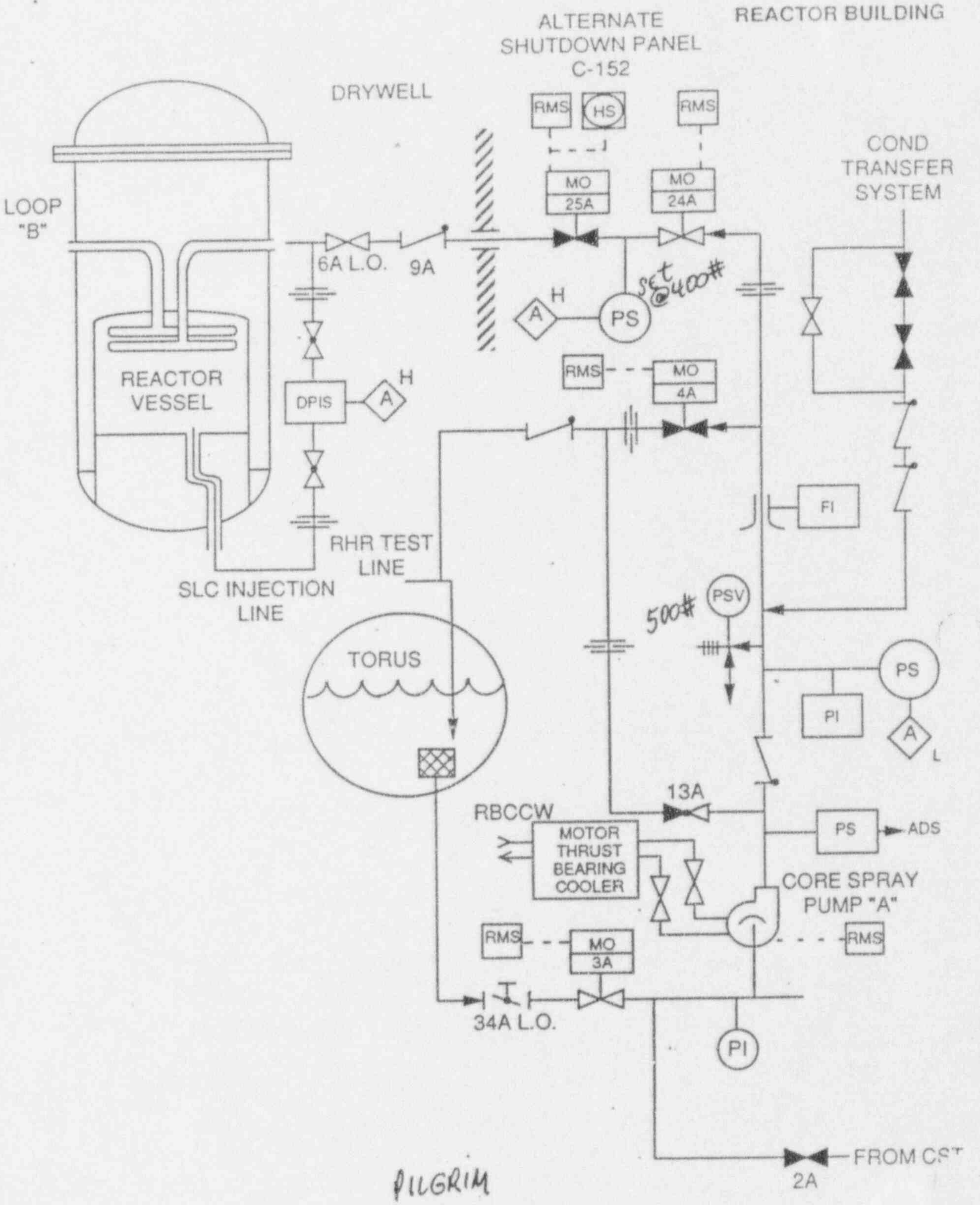
EDG building ventilation air flow in conjunction with this periodic operational test. The air flow measurements were collected to support assessment of EDG operability under various ventilation lineup configurations. The inspector monitored the test from the EDG building. The local operator demonstrated strong knowledge of the surveillance procedure and EDG material condition.

4.0 ENGINEERING (37828, 71707, 92700, 92701)

4.1 Core Spray Isolation Valve Leakage

In late October 1993, system engineers identified slightly elevated temperatures on the upstream side of the inboard "B" loop core spray discharge isolation valve (MO-1400-25B). Piping temperature was approximately 130 degrees F (50 degrees F above ambient room temperature). Core Spray loop "B" header pressure remained normal (110 pounds per square inch gage (psig)). This was characteristic of minor backleakage from the reactor vessel (RV) past a normally closed injection check valve (1400-9B) and the normally closed MO-1400-25B. System engineers initiated monitoring of core spray (CS) pressure and temperature to determine the extent of the leakage. Significant backleakage from the RV to systems with lower design pressures, such as core spray, could increase the likelihood of an intersystem loss of coolant event. In addition, excessive leakage could result in void formation within CS system piping, resulting in a hydrodynamic effect called water hammer which can cause piping damage during system operation. The inspector noted that CS piping temperature remained approximately 200 degrees F below that necessary to cause boiling at the current system pressure. Therefore, the likelihood of void formation and subsequent water hammer is very low.

Through mid-December, CS pressure and temperatures remained relatively constant. The inspector reviewed pertinent control room indications and discussed response in the event of indication of increased CS leakage with operators. Indication of both "A" and "B" loop CS pressure and system high pressure alarms (at 400 psig) are available in the control room. Operators confirmed that CS pressures had remained normal, and that no air had been observed when venting the CS system high point vent during routine surveillances. Monthly CS pump and valve operation surveillances were successfully completed and indicated no degradation of system performance. Operators demonstrated detailed knowledge of Alarm Response Procedure C903R-C1, "Core Spray B Valve Leakage Hi Pressure." The inspector concluded that system engineers and operators were properly monitoring CS system performance and were prepared to take appropriate action if CS leakage degraded significantly.



CORE SPRAY SYSTEM (Loop A)

FIGURE 1 REV. 2

2tr113g

Operations section management requested an engineering assessment of the observed elevated CS piping temperature. The assessment considered inservice test (IST) program history for valve leak rate tests, valve timing, current CS pressure and temperature data, and prior leakage history of the residual heat removal system. Engineers believe that small inevitable leakage past 1400-9B is caused by slow heating and pressurization of the intervening piping between the check valve and MO-1400-25B (see CS piping schematic). Less than full system differential pressure across the check valve allows it to come off its seat which subjects MO-1400-25B to reactor coolant system pressure. Consequentially, any leakage past this valve is experienced in the upstream piping. Periodic cycling of the CS injection isolation valves (MO-1400-25B and 24B) under the IST program tends to reseat the check valve and ameliorate the leakage. The inspector observed that MO-1400-25B leak rate testing had been conducted during the last (May 1993) refueling outage with satisfactory results. The licensee concluded that the CS isolation valves will continue to satisfy their containment isolation function and that the CS system remained operable. The inspector discussed the assessment with system engineers and had no concerns.

In late December, the inspector observed that "B" loop CS pressure had risen approximately 15 psi over a ten day period. "B" CS piping temperature had remained at 130 degrees F and "A" loop pressure remained at 110 psig. Although the "B" loop pressure was of concern, CS loop pressures both remained well below the high pressure alarm setpoint of 400 psig and the CS relief valve setpoint of 500 psig. The inspector discussed the pressure rise with licensee engineers who had been reviewing recent CS system maintenance history. The inspector noted that the pressure increase began following the monthly CS pump operability surveillance on December 20, 1993. BECo system engineers proposed that the pressure increase did not necessarily represent greater leakage past MO-1400-25B, but may indicate that other "B" loop boundary valves (operated during the pump surveillance) were now seated tighter than before the surveillance; the CS full-flow test line isolation valve (MO-1400-4B) was a likely candidate. A test plan was developed to better identify and trend the "B" loop CS leakage. On December 30, the piping upstream of MO-1400-25B was vented to establish a baseline value. At the close of this report period, loop "B" CS pressure remained unchanged at 110 psig.

Engineers further discussed the long term effect of continued seat leakage on the performance of MO-1400-25B. The valve seat is made of stellite, a material susceptible to steam cutting as water leaks from the high pressure side of the seat to the low pressure side. However, the seat will not degrade quickly. In parallel with efforts to better assess the "B" loop CS leakage, the licensee prepared a temporary modification to the CS system lineup as a contingency in the event that the MO-1400-25B leakage became significant. The modification would shut MO-1400-24B and open MO-1400-25B as the normal CS system standby lineup. Both of the CS injection isolation valves indicated good leak tightness during their latest IST program leak tests. Engineers intend to perform leak rate tests on MO-1400-24B, 25B, and 9B during the next midcycle maintenance outage (November 1994). The inspector concluded that licensee actions to assess elevated CS piping temperature were comprehensive. Operations, Maintenance, and Engineering personnel coordinated efforts effectively to monitor CS leakage and determine operability.

4.2 (Closed) URI 50-293/91-201-07, Reactor Water Level Setpoints

This item pertained to the reactor vessel (RV) water level low-low setpoint which initiates the automatic actuation of high pressure coolant injection (HPCI) and other protective devices to mitigate the effects of degrading RV water level. The inspectors questioned the basis of the existing setpoint, for which the licensee did not have a supporting calculation documented. The licensee had determined (from General Electric data) that the analytical limit for HPCI initiation (low-low level) was -56.9 inches referenced to instrument zero. The existing Technical Specification limit was -49.0 inches for low-low level initiation. The existing setpoint was established at -46.0 inches. The licensee prepared a preliminary calculation that incorporated a total loop uncertainty of 10.2 inches. Approximately 8.0 inches of the uncertainty were associated with heat-up of the instrument reference leg during a design basis pipe break within containment, for which mitigating actions for the low-low RV level condition would be required. The NRC inspection team had previously determined that the preliminary calculation was acceptable for interim use.

The effect of the error in level measurement was not identified in either plant design change (PDC) 85-07 which relocated the reference leg outside of containment, or in PDC 84-70 which replaced the original instrumentation with the analog trip system. The equipment qualification data file identified the line break environment for the transmitter, but did not identify the effect on the reference leg or consider the effect in the safety evaluations and engineering analyses supporting the two modifications. The licensee stated that implementation of these modifications contributed additional margin, between the existing setpoint of -46 inches and the analytical limit of -56.9 inches, beyond the margin provided by the original design which had not been in question. Therefore, there was no need for the supporting safety evaluations to address the effects of a pipe break outside containment on the reference legs. Additionally, the licensee noted that the reference legs were moved outside of containment to avoid flashing, an issue unrelated to this setpoint concern.

During a followup NRC inspection conducted in April 1993, Boston Edison stated their plans to improve setpoint calculations as part of their Setpoint Control Program. These calculations will be performed to determine setpoints and allowable values of instruments in accordance with Instrument Society of America (ISA) Standard S67.04, "Setpoints for Nuclear Safety-Related Instrumentation Used In Nuclear Power Plants - 1982" and Regulatory Guide 1.105, Rev. 2, "Instrument Setpoints for Safety-Related Systems." Subsequently, loop uncertainties such as reference leg heat-up, will be considered within the calculations.

As part of the licensee's setpoint program to develop calculations for all safety-related equipment, calculation number I-N1-97, project number 25-226, was completed to maintain the existing RV water level low-low setpoint while accounting for loop measurement uncertainty. This calculation and others in the program were performed to support an increase in fuel cycle duration from 18 to 24 months. Results of calculation I-N1-97 showed that the existing setpoint was adequate when consideration of a design basis pipe break was given.

The inspector noted that Boston Edison had submitted a Technical Specification revision request to change the RV water level low-low limit from -49 inches to -46.3 inches for additional margin between this value and the vendor's analytical limit. The inspector compared this change with the calculated value presented in I-N1-97 and determined this new limit was conservative. Based on review of the setpoint calculation and margin available, including the licensee's plan to increase this margin, the inspector determined the RV water level low-low setpoint was adequate to provide automatic initiation of HPCI under accident conditions. This item is therefore closed.

5.0 PLANT SUPPORT (71707)

The inspector reviewed security program performance during routine plant tours. Security force members were observed to be alert and aware of posting requirements. Appropriate compensatory postings were observed to be in place during heavy weather conditions on several occasions during January 1994.

Positive radiological controls were also observed during routine plant tours. Radiological protection technician presence provided positive controls at the radiological control area access point. Technical presence was also noted within the process buildings. Proper postings were noted and survey maps reviewed were observed to be current. Portal and hand held monitors were observed to be in good condition and within proper calibration periodicities.

6.0 SAFETY ASSESSMENT/QUALITY VERIFICATION

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 93-04**

LER 93-04, "Automatic Scram Resulting From Load Rejection at 100 Percent Power and Subsequent Loss of Preferred Offsite Power," dated April 12, 1993, describes the March 13, 1993 reactor scram and partial loss of offsite power during a severe winter storm. The event was documented in NRC Inspection Report (IR) 50-293/93-05. Two NRC concerns were identified during the event review. Specifically, upon receipt of the load reject, the Y-3 and Y-4 electrical busses had tripped unexpectedly, and during reactor cooldown, the technical specification limits on temperature and pressure were exceeded for the reactor vessel bottom head. Subsequently, these concerns were dispositioned as violations cited by a Notice of Violation that was issued in NRC IR 50-293/93-06.

Excellent event description was developed within the LER. Initial corrective actions to the Y-3 and Y-4 deenergization, and the failure to identify and evaluate exceeding the reactor bottom head pressure and temperature limits, were consistent with the actions described in NRC IR 50-293/93-05 and in the licensee's response to the violation dated June 18, 1993. The LER appropriately addressed the reporting criteria.

- **LER 93-05**

LER 93-05, "Automatic Closing of the Reactor Water Cleanup System Isolation Valves," dated April 9, 1993, describes the March 14, 1993, cleanup system automatic isolation during system flow manipulations. At the time of the isolation, the reactor was shutdown with operators attempting to increase reactor vessel bottom head coolant flow by throttling the reactor water cleanup system suction valve, RWCU-85, prior to entering shutdown cooling system operations. Being a gate valve, RWCU-85, is not effective for fine throttling. As the valve was opened, the associated system flow instrumentation sensed a momentary high flow condition and initiated the primary containment isolation system Group VI actuation. The cleanup system isolated as designed, and the event presented minimal operational impact. Following a brief review that verified the isolation occurred due to a momentary high flow condition during throttling of RWCU-85, the isolation was reset and the system was returned to service within thirty minutes.

In addition to resetting of the isolation, corrective actions included a review of the governing procedure, 2.2.83,"Reactor Cleanup System." The existing procedure revision provided a caution statement regarding the operation of RWCU-85 as a throttle valve, and no further changes were necessary. The inspector discussed the event with operations section management, the system engineer, and the lead instrumentation and control engineer. The system drawing and operating procedure were also independently reviewed. The inspector concluded the LER causal analysis was accurate, and that the LER properly addressed the reporting criteria.

- **LER 93-22**

LER 93-22, "Loss of Preferred Offsite Power and Automatic Scram Resulting from Load Rejection at 100 Percent Power", dated October 12, 1993, describes plant response to the September 10 lighting strike within the 345 KV electrical distribution switchyard. A storm rapidly developed the morning of September 10 and caused disturbances on the off-site electrical distribution grid. One of the two 345 KV supply breakers to the station startup transformer (ACB-103) had been opened and isolated for maintenance earlier that day. At 10:27 am, one of the two 345 KV off-site power supply lines (Canal line) briefly deenergized due to the storm. Switchyard breaker protective relays sensed the voltage degradation and caused ACB-104 to open, thereby isolating the station from the degraded portion of the off-site distribution grid. The Canal line was quickly reenergized. However, once opened, ACB-104 could not be reclosed due to protective circuits associated with the tagout and isolation of ACB-103. The switchyard remained disconnected from the Canal line. Operators began clearing tags for the restoration of ACB-103 and ACB-104. Before tags were cleared, a lightning strike occurred on the second 345 KV power line within the switchyard. The electrical transient caused ACB-105 to open which disconnected the station from the remaining off-site 345 KV power line. The reactor automatically tripped due to a turbine generator load reject condition. All safety systems responded as designed. Additional detail of operator and plant response to the event is documented in NRC Inspection Report 50-293/93-15.

The LER discussion of component design response and safety consequence analysis was excellent. Reportability criteria were properly addressed. The inspector had no further questions regarding this event.

- **LER 93-24**

LER 93-24, "High Pressure Coolant Injection (HPCI) System Inoperable due to Inoperable Motor Operated Valve (MOV)", dated October 29, 1993, documents the September 30, 1993 licensee determination that the outboard HPCI steam isolation valve (MO-2301-5) had insufficient thrust to ensure closure against a design steam line break. In late September, the licensee questioned existing industry guidance concerning the use of running efficiency versus pullout efficiency when calculating DC powered MOV torque output capability in the close direction. Upon clarification from the vendor the licensee reevaluated all DC-powered MOVs and concluded that MO-2301-5 was inoperable. Further event detail and corrective actions are documented in NRC Inspection Report 50-293/93-19.

The LER thoroughly described the event and developed the engineering methodology which identified the incorrect application of the efficiency factor. The inspector independently reviewed the schedule of upcoming MOV maintenance and noted that a modification to MO-2301-5 to restore full design margin is scheduled for the next refueling outage. The LER correctly addressed all report criteria in accordance with 10 CFR 50.73.

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 report period, the resident inspector staff conducted an exit meeting on January 25, summarizing the preliminary findings of this inspection. No proprietary information was identified as being included in the report.

7.2 Management Meetings

On December 17, a licensee management meeting was conducted in the NRC Region I office to discuss the reliability of the high pressure coolant injection and reactor core isolation cooling systems. Licensee actions to reduce switchyard susceptibility to weather related power interruptions were also discussed. The licensee's presentation slides are attached.

7.3 Other NRC Activities

On December 7, a full participation Emergency Preparedness Exercise was conducted. A team of approximately 40 NRC personnel participated in the exercise. Separately, NRC Region I emergency preparedness specialists inspected licensee performance during the exercise. Results of the inspection will be documented in NRC Inspection Report 50-293/93-18.

On December 13-17, an NRC Region I plant systems specialist and an NRC contractor conducted an inspection of the motor operated valve program. Inspection results will be documented in NRC Inspection Report 50-293/93-22.

Boston Edison Pilgrim Nuclear Power Station

Switchyard / HPCI / RCIC Improvement Plans

Agenda

- Discuss actions taken to enhance performance of Switchyard/345 KV Transmission System and HPCI/RCIC Systems
- Discuss results of steps taken
- Outline future actions

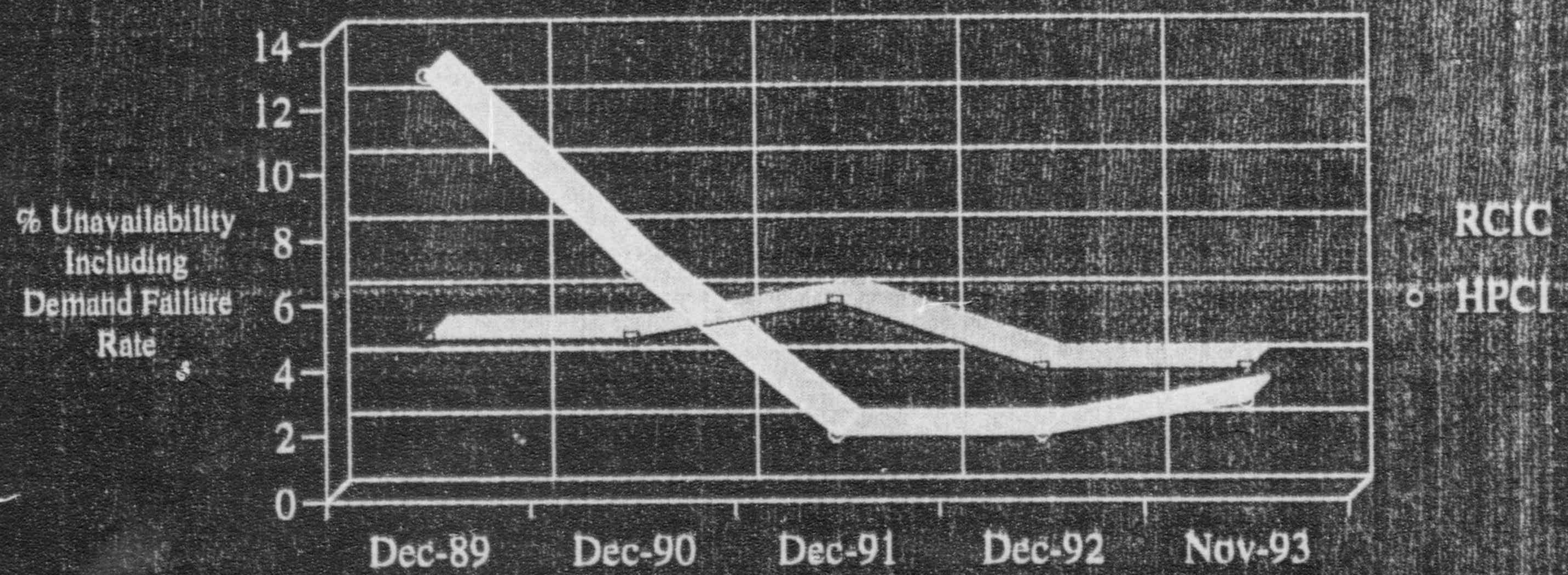
HPCI And RCIC Are Important Safety Systems

- Boston Edison Management became concerned with HPCI and RCIC performance in the fall of 1990
- 1992 PRA/IPE Submittal indicated HPCI/RCIC are key systems
- HPCI/RCIC Availability important if switchyard unavailable

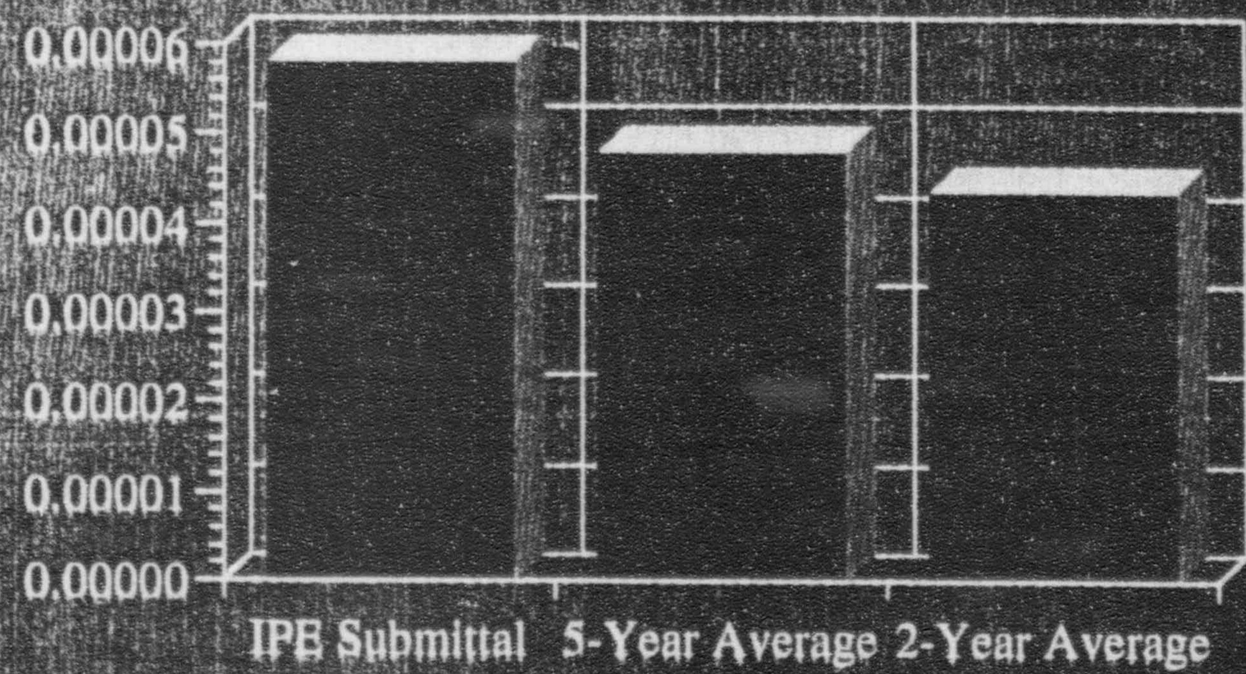
HPCI/RCIC Background

- High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems are high pressure steam driven systems.
- 10 LERs involving HPCI or RCIC in 1993
- In some 1993 LERs, systems were available for operation until intentionally removed from service.

Pilgrim HPCI And RCIC Performance From 1/189 to 11/30/93



Impact Of Improving HPCI & RCIC Performance on PNPS Core Damage Frequency



HPCI/RCIC Improvement Plan

- Integrated action plan developed
- Identifying 56 items to enhance availability.
- 46 of original 56 items acted upon.
- Plan is living, subject to evolution.
- 8 items added since inception.

Examples Of HPCI/RCIC Improvement Items

- Steam leak detection Instrument connector modification
- RCIC Steam Admission Valve replacement
- HPCI Governor Valve Power Piston Spring replacement

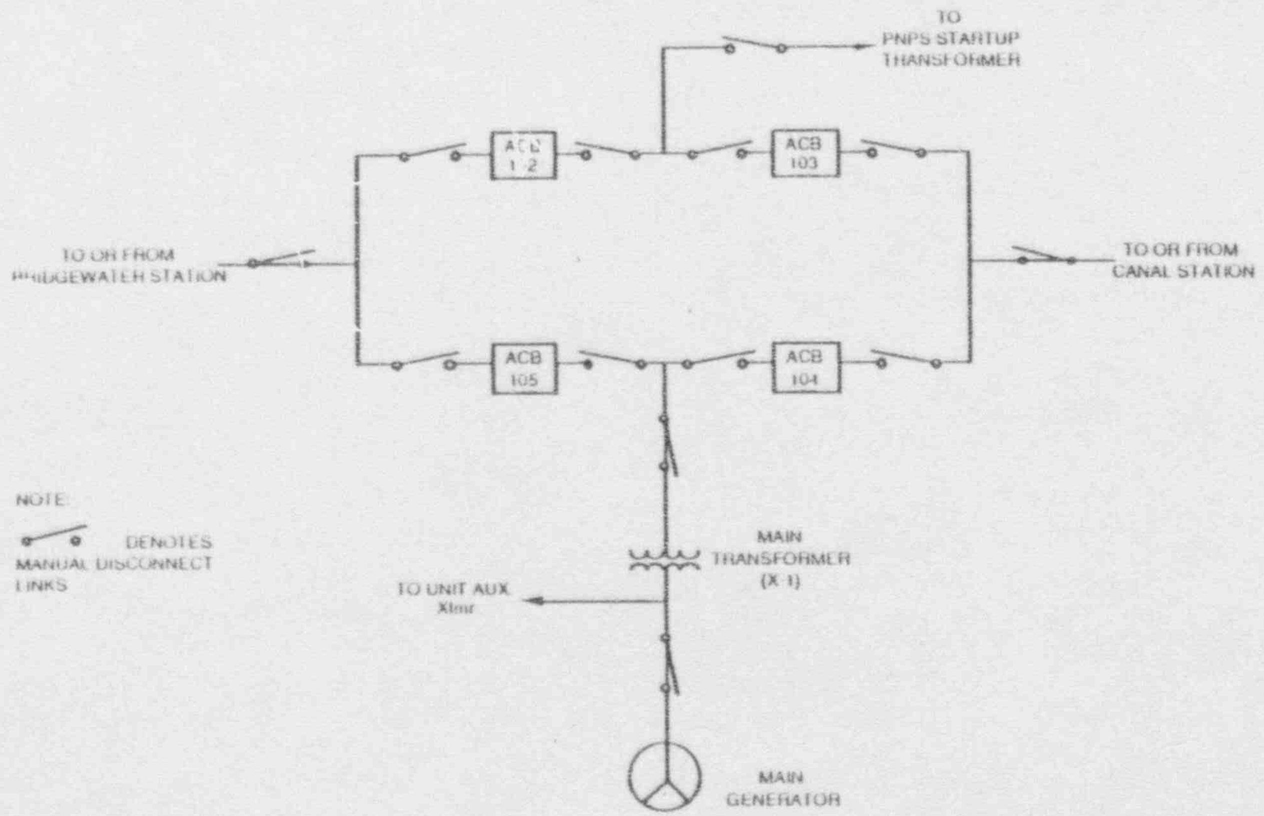
Additional HPCI/RCIC Improvements Planned

- Replacement of HPCI Turbine Steam Inlet Valve
- Replacement of RCIC Oil Filter
- Motor Operated Valve enhancements
- Evaluate High Steam Flow Instrument Setpoints

Why Enhance Switchyard/345 Kv Transmission System Performance

- Switchyard close to ocean
- Salt deposits on 345 KV insulators
- 345 KV Circuit Breaker maintenance

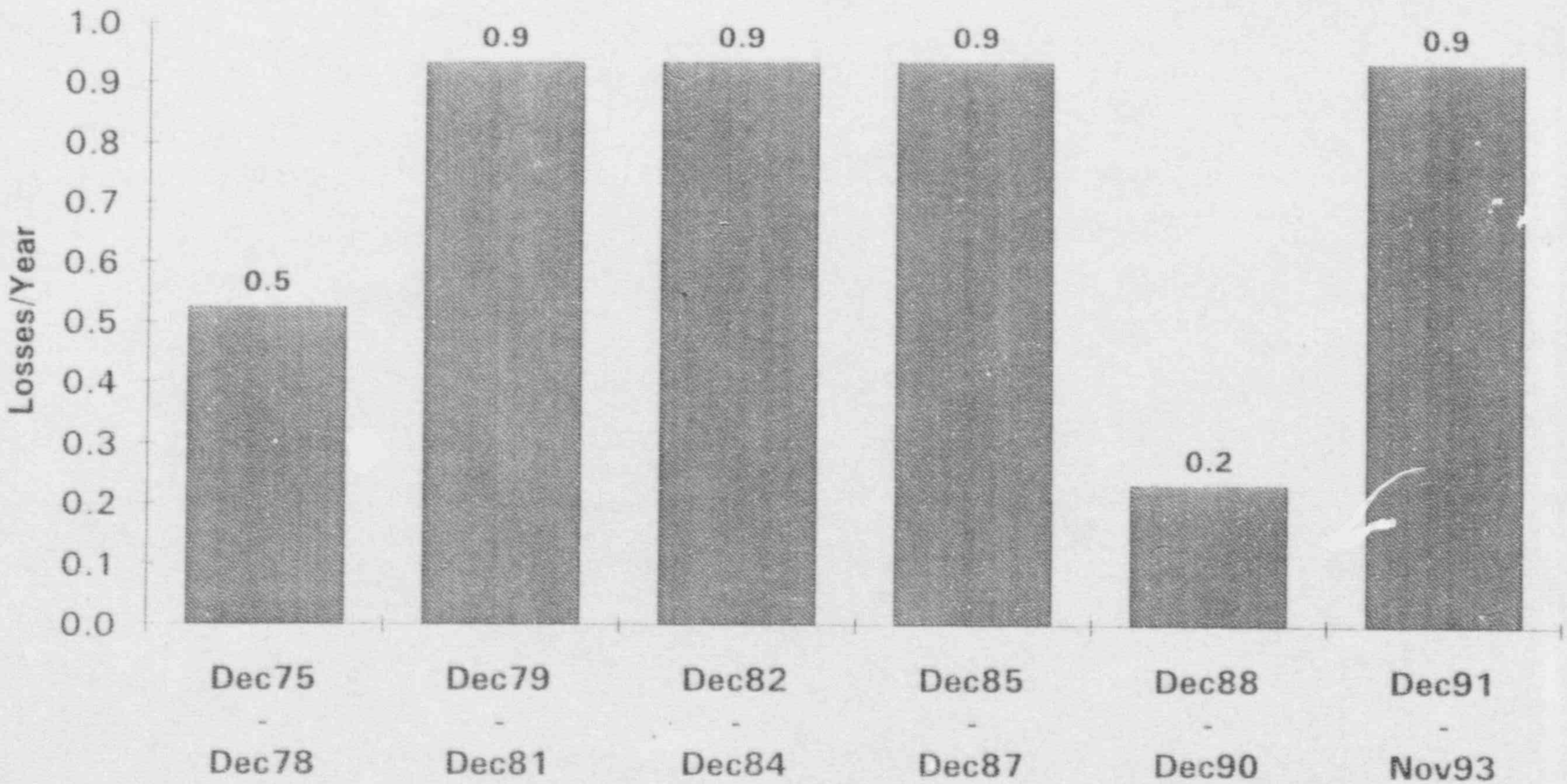
Switchyard/345 Kv Transmission System



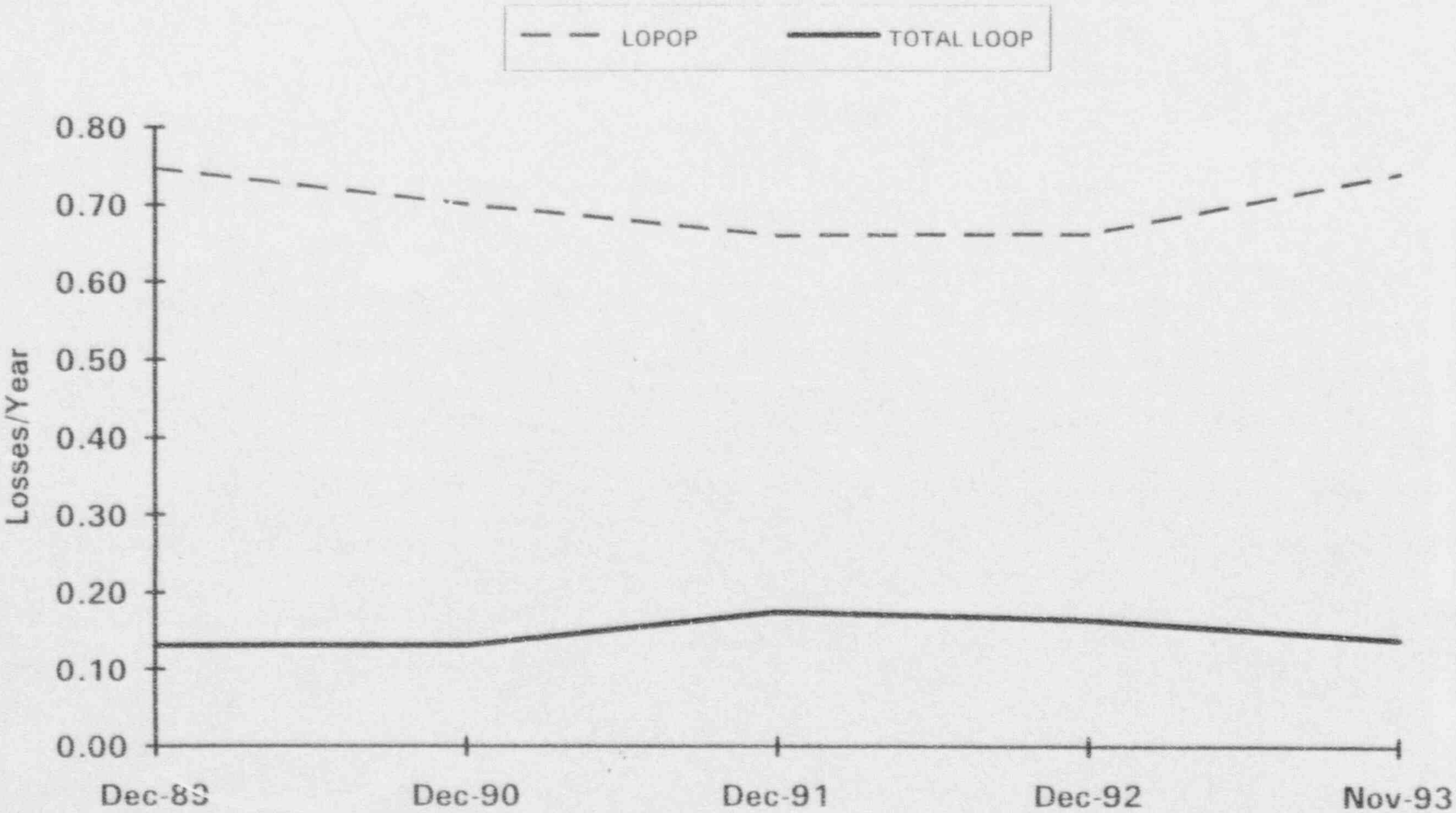
Switchyard Background

- Switchyard is a 345 KV Ring Bus
- Can function without one ACB or one Transmission Line
- 5 Plant Trips involving Switchyard from 1989 to 1993.

PILGRIM LOSS OF PREFERED OFFSITE POWER FREQUENCY: COMPARISON OF SUBSEQUENT THREE AND FOUR YEAR PERIODS



MOVING AVERAGE LOOP FREQUENCY FROM 1/1/75 to 11/30/93 (1/1/89 to 11/30/93) SHOWN



Switchyard Reliability Task Force Formed

- Cause of reduced 345 KV insulator coating performance is loss of coating hydrophobicity.
- Evaluating 345 KV maintenance practices

Actions Taken On Insulator Coating Performance

- Cleaned and recoated 345 KV insulators on selected sections of Switchyard
- Sample insulators sent to EPRI for testing
- Switchyard Events Recorder installed

Actions Taken To Enhance 345 KV Breaker Maintenance

- Recent ACB 103 Maintenance witnessed by Consultant.
- Consultant alignment recommendations implemented
- No leakage on ACB 103 since alignment
- Same alignment performed on ACB 102 and ACB 104 with no leakage

Task Force Options Under Consideration

- Refurbish the existing ACBs and maintain RTV Coatings
- Replace ACBs with newer design and replacement of insulators
- Replacement of the existing Switchyard with an SF6 Switchyard
- Refurbish the existing ACBs and replacement of insulators

INTEGRATED IMPACT OF RECENT HPCI, RCIC AND LOOP PERFORMANCE ON PILGRIM CORE DAMAGE FREQUENCY