U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/ Report No.	50-213/94-05
License No.	DPR-61
Licensee:	Connecticut Yankee Atomic Power Company (CYAPCo) P. O. Box 270 Hartford, CT 06141-0270
Facility:	Haddam Neck Plant
Location:	Haddam Neck, Connecticut
Dates:	February 27 to April 5, 1994
Inspectors:	William J. Raymond, Senior Resident Inspector Peter J. Habighorst, Resident Inspector John T. Shedlosky, Project Engineer, Section 3A, DRP

Approved by: Lawrence T. Doerflein 5/20/94
Lawrence T. Doerflein, Chief Date
Reactor Projects Section No. 4A

Areas Inspected: NRC resident inspection of plant operations, outage activities, plant start-up, maintenance, engineering and technical support, and plant support activities.

Results: See Executive Summary

EXECUTIVE SUMMARY

HADDAM NECK PLANT INSPECTION 50-213/94-05

Plant Operations

The inspector noted that operator actions to heat-up the reactor coolant system and achieve reactor criticality were controlled well.

The inspector noted that the March 28 automatic reactor trip was due to a failure of breaker 309-1A to close. The cause was believed to be the closing spring failing to operate. However, the next day the cause could not be replicated during maintenance troubleshooting activities. All safety systems responded as design post-trip. Operators took prompt actions to terminate the plant cooldown. The inspectors concluded that normal operating procedure 2.1-6 contributed to the reactor trip by creating an operating envelope that was restrictive.

The inspection of the component cooling water system concluded that it was maintained in a good operational status. An inspector follow item was developed concerning CYAPCo actions to quantify reactor coolant system leakage parameters into the component cooling water system **(IFI 94-05-01)**.

Maintenance

The inspector noted good attention-to-detail by a maintenance electrician who identified a wrong replacement diesel air start solenoid during a pre-job walkdown. Procurement engineering disposition of a replacement item evaluation (RIE) incorrectly documented the characteristics of the installed solenoid. This issue is unresolved **(URI 94-05-02)** pending a review of RIE's processed in accordance with the requirements of NEO 6.12 to determine if this was a programmatic weakness.

The inspector expressed concern to CYAPCo on repeated stroking of main steam isolation valves in a cold shutdown condition. The numerous valve strokes were prompted by a necessity to loosen the valve packing for a hot standby surveillance. This is an inspector follow item **(IFI 94-05-03)**.

The inspector identified that a valve lineup was completed on the service water system with an incomplete checklist. Licensee immediate actions to address the finding were thorough. Licensee followup actions were in progress to address the completeness of operations files in the control room, to review completed surveillances and to address the adequacy of supervisory approvals. This item is unresolved **(URI 94-05-04)**.

Engineering and Technical Support

The inspector identified no inadequacies in the scope of service water modifications performed, or in the implementation of the design.

The inspector noted that CYAPCo staff performed well to investigate the MCC-5 automatic Bus transfer scheme. The modified scheme should improve overall reliability because it will reduce the number of operation demands.

A good questioning attitude by a system engineer identified a system alignment deficiency in an emergency operating procedure. Appropriate corrective actions were taken by the licensee.

Plant Support

Three events reported as conditions prohibited by technical specifications (LER 93-19, 94-03 and 94-04) were not cited based on satisfying the criteria of Section VII.B of 10CFR 2, Appendix C (NRC enforcement policy). The above LER's accurately described the events and their safety significance. Two previous violations in inspection report 50-213/93-21 were closed. Three items require more NRC inspection and remain open (50-213/94-03-04, 93-22-04 and 94-03-01).

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Note: The NRC inspection manual procedure or temporary instruction (TI) that was used as inspection guidance is listed for each applicable report section.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

At the start of the period, the plant was in a cold shutdown condition. Major maintenance activities completed during the outage included the replacement of safety-related service water piping, the replacement of containment air recirculation coolers, the replacement of the No. 1 reactor coolant pump seal, and reactor cavity painting. The licensee established containment integrity on March 25. Plant heat-up began on March 26, and the reactor was made critical on March 28 at 12:34 p.m. (report detail 2.2).

An automatic reactor trip occurred on March 28 at 10:27 p.m. (report detail 2.3). The reactor was again made critical on March 29, and power operation continued until the end of the inspection period.

2.0 OPERATIONS (71707, 71710 and 93702)

In addition to normal utility working hours, the inspectors routinely conducted the review of plant operations during portions of backshifts (evening shifts) and deep backshifts (weekend and night shifts). Inspection coverage was provided for thirty-five hours during backshifts and thirty-three hours during deep backshifts.

2.1 Operational Safety Verification

This inspection consisted of selective examinations of control room activities, operability reviews of engineered safety feature systems, plant tours, review of the problem identification systems, and attendance at periodic planning meetings. Control room reviews consisted of verification of staffing, operator procedural adherence, operator cognizance of control room alarms, control of technical specification limiting conditions of operation, and electrical distribution verifications. Administrative control procedure (ACP) - 1.0-23, "Operations Department Shift Staffing Requirements," identifies the minimum staffing requirements. During the inspection period, the inspector verified these requirements were met.

The inspectors reviewed the onsite electrical distribution system to verify proper electrical line-up of the emergency core cooling pumps and valves, the emergency diesel generators, radiation monitors, and various engineered safety feature equipment.The inspectors also verified valve lineups, position of locked manual valves, power supplies, and flow paths for the high pressure safety injection system, the low pressure safety injection system, the containment air recirculation system, the service water system, and the emergency diesel generators. No deficiencies were noted.

Bypass jumpers were reviewed against the requirements of Work Control Manual 2.2-2, "Jumper, Lifted Lead, and Bypass Control," with emphasis on proper installation and the content of the safety evaluations. The inspector reviewed all jumpers for age, and verified that Plant Operations Review Committee (PORC) evaluations were completed to disposition longstanding evaluations. The jumpers reviewed were found to be in accordance with administrative requirements.

Tagouts

The inspectors reviewed equipment tagouts against the requirements of ACP 1.2-14.2, "Equipment Tagging". The inspectors verified that the proper equipment was tagged, equipment identified within technical specifications was appropriately controlled, and equipment isolation was proper based on work observations, controlled drawings, and procedural guidance. Tagouts reviewed were: 940195, "Isolate North Service Water Header," and 940193, "Isolate Screen House Header for Maintenance". The inspectors also reviewed other tagging operations by comparing the tags installed throughout the plant with the tagout sheets maintained in the control room. The inspectors determined that the equipment reviewed was appropriately isolated and the tagouts met the technical specification requirements and administrative controls.

Log-Keeping and Turnovers

The inspectors reviewed control room logs, night order logs, plant incident report logs, and crew turnover sheets. No discrepancies or unsatisfactory conditions were noted. The inspectors observed crew shift turnovers and determined they were satisfactory, with the shift supervisor controlling the turnover. Plant conditions and evolutions in progress were discussed with all members of the crew. The information exchanged was accurate. During attendance at daily planning meetings the inspector noted discussions were held which identified maintenance and surveillance activities in progress. The inspectors conducted periodic plant tours in the primary auxiliary building, turbine building, containment building, and intake structures. The inspectors noted plant housekeeping was satisfactory.

2.2 Plant Start-up Activities

The inspector reviewed operator activities in progress on March 26 to prepare the reactor for startup. A plant heat up was in progress in accordance with NOP 2.1-1, "Startup from Cold Shutdown to Hot Standby." The inspector independently verified operator actions to isolate the low temperature overpressure relief valves, and actions to establish a steam bubble in the pressurizer. The reactor entered Mode 3 at 4:55 p.m. The inspector reviewed plant status from the control room and reviewed the status of safety systems during a system walk down in the primary auxiliary building. The inspector reviewed the system and equipment status against the requirements of the technical specifications and the prerequisite conditions for plant restart identified in NOP 2.1-1, Attachment 2, "Technical Specification Verification Checklist". The inspector verified that plant system conditions were normal for the operational mode. The inspector determined that the operator actions to heat-up the reactor coolant system were controlled well.

The inspector toured the plant and noted that housekeeping conditions were generally very good following the construction during the outage. One exception was in the Adams filter area on the upper level of the primary auxiliary building. The inspector discussed his concerns with the duty shift supervisor, who noted the comments and stated that the conditions had also been identified by the operations crew and that plant maintenance had been requested to address the area. The inspector toured the area again on March 30 and noted housekeeping conditions were much improved.

The inspector reviewed the computerized tagging system and the log of outstanding tags to verify plant systems were operational as needed for plant restart. No inadequacies were identified. The inspector also completed an audit of the outstanding jumpers and system bypasses in effect, based on the requirements of Work Control Manual 2.2-2, "Jumper, Lifted Lead and Bypass Control." This review verified that none of the outstanding jumpers would adversely impact systems needed for plant restart. The inspector noted further that the licensee completed the periodic reviews of outstanding jumpers pe the requirements of WCM 2.2-2.

The inspector conducted a walk down of the high pressure safety injection, the low pressure safety injection and the service water system to independently verify the system valve lineups were proper. The service water system was selected for verification because it was extensively impacted during the plant outage. This review verified that the tagouts written for the system under Clearance 940249 were properly removed by the operations staff. No inadequacies were identified. All system valves were found to be in the proper position based on a comparison with plant procedures SUR 5.1-152, "Service Water System Alignment," and NOP 2.24-1, "Service Water System Valve Lineup Checklist." Based on this review, the inspector determined that the SW system was properly restored from the construction conditions associated with the outage, and was properly aligned to support plant startup. A finding regarding the licensee's completion of SUR 5.1-152 is described in Section 3.2 of this report.

On March 28, the inspector observed the approach to criticality. Operators were implementing NOP 2.1-2, "Reactor Startup." The inspector verified prerequisite conditions (steps 4.3 - 4.20 of NOP 2.1-2) were complete satisfactorily. During implementation of NOP 2.1-2, the inspector observed that the primary reactor operator performed the reactor trip at step 6.4.8 by depressing the manual pushbutton on the control rod panel instead of the required turbine-generator section as described in the procedure. The reactor operator notified the shift supervisor of his mistake. The inspector did not consider this attention to detail issue significant as both manual pushbuttons were successfully checked prior to this step, and was a isolated case despite the numerous other activities on-going in the control room at the time. The inspector had no further concerns regarding this issue. The inspector noted good coordination between operations and chemistry personnel on sampling of reactor coolant system and pressurizer boron concentration. The inspector also reviewed the locked valve checklist for operational mode 2 for completeness. No deficiencies were noted.

Conclusion

The inspector determined that operations department control and implementation of applicable procedures during the plant heat-up and reactor criticality were performed well.

2.3 Reactor Trip

Event Description and Plant Response

On March 28, at approximately 10:27 p.m., the unit experienced an automatic reactor trip. The reactor trip was a result of low reactor coolant loop flow. The low flow trip was a result of an undervoltage condition on the non-safety grade reactor coolant Bus 1-1A. Reactor coolant pumps 1 and 2 were de-energized for approximately six seconds until the secondary reactor operator energized Bus 1-1A from off-site power. The operators at the time were transferring the reactor coolant pump buses from the off-site power supply to the unit auxiliary transformer using NOP 2.1-6, "Reactor Just Critical to Minimum Load."

The inspector evaluated the post-reactor trip plant response by reviewing the sequence of events, operator interviews, alarm logs, and the post-trip report. The inspector concluded that all safety systems responded as design. All control rods inserted into the core and no primary or secondary code safety valves lifted. The inspector noted a post-trip cooldown on the primary system of approximately fourteen degrees Fahrenheit (535°F to 521°F). The cooldown resulted in expected increase in charging flow and a decrease in pressurizer level to 21%. Approximately eight minutes after the trip, control room operators shut the main steam isolation valves as required in emergency operating procedure ES 0.1 step 1.d. CYAPCo attributed the cooldown to a combination of low reactor decay heat, elevated steam generator blowdown flows, and increased steam generator levels. The plant cooldown terminated upon shutting the main steam isolation valves. The inspector did not identify any other potential causes for the plant cooldown.

Trip Investigation and Assessment of Operator Performance

The inspector reviewed the plant logs, applicable procedures and interviewed operations personnel regarding the sequence of events surrounding the failed attempt to transfer the reactor coolant buses from the off site supply to the unit auxiliary transformer, T309. The bus transfer attempt and reactor trip occurred as the operators implemented NOP 2.1-6. The objective of NOP 2.1-6 is to provide the operators instruction necessary to bring the plant from Mode 2 (just critical) to a minimum load of about 30 MWe, with the main generator phased to the electrical grid. The licensee's and the inspector's review of the event determined the sequence of events and factors described below contributed to the trip.

Plant operators had completed Step 6.3 of NOP 2.1.6, which phased the generator to the grid and were performing Step 6.4 to align plant systems in preparation for the power ascension. To complete this evolution, the NOP directs the operator to stabilize power, transfer the RCP electrical buses to the unit auxiliary transformer, align the auxiliary steam and feedwater systems, and then increase plant power.

The NOP directs the operator to stabilize load and reactor power in a narrow band, defined (i) on the low side by the need to maximize generator load as much a possible so as to minimize swings in MWe due to governor instabilities in the low load regions; and (ii) on the high side by the need to keep nuclear instrumentation (NI) power less than about 7% full power, due to the P-7 reactor protection system interlock. In the past, governor instabilities have resulted in load swings of about 7 MWe with the generator output nominally at 12 MWe, which decrease to swings of 4 MWe with generator load at 20 MWe. The low side limit on MWe is based on the need to keep load high enough to avoid a reverse power condition on the generator.

Step 6.3.8 of NOP 2.1-6, Revision 19 (in effect on March 28), required the operator to increase load to approximately 20-30 MWe prior to transferring the electrical buses, while at the same time keeping NI power less than about 6% power to prevent the P-7 interlock from clearing. Since the Haddam Neck electrical generation at rated full power conditions is about 600 MWe, the operational window to conduct the transfer is established by NOP 2.1.6 at about 3.5% to 5% power on the low side to about 6% power on the high side.

On increasing power, P-7 automatically enables reactor trips on low flow in more than one reactor coolant loop, reactor coolant bus undervoltage, more than one reactor coolant pump breaker open, main steam isolation valve closure, turbine trip and variable low pressure. The P-7 interlock is annunciated on the main control board; the normally illuminated window "clears" during plant startup to enable the "at power" trips when NIs indicated power is 6% to 7% on 2 of 4 NI power range channels. By design, the P-7 interlock also receives an input from turbine first stage pressure, such that either NI power or first stage pressure above the value equivalent to 7% power is sufficient for the interlock to clear and thereby enable the "at power" trips. Turbine first stage pressure can be affected by governor instabilities, such that it is possible for P-7 to clear even though NI power is stable or decreasing.

The need to transfer the RCP Buses below the P-7 interlock is mandated by the design of the transfer scheme, and is controlled by Step 6.4.2 of NOP 2.1-6. The transfer is accomplished by opening RCP bus supply breakers from the off site supply, and then closing the supply breakers for the on site supply. For bus 1-1A (which powers the #1 and #2 RCPs) breaker B-3 T1A connecting bus 1-1A to bus 1-3 is opened, and breaker B-309-1A is closed to power the bus from T309. For bus 1-1B (which powers the #3 and #4 RCPs) breaker B-2T1B connecting bus 1-1B to bus 1-2 is opened, and breaker B-309-1B is closed to power the bus from T309. The transfer occurs automatically in a "break-before-make" sequence once initiated by the operator when he places the control switch for the on site feeder breaker in the closed position. The NOP directs the transfer to occur sequentially by first transferring RCPs off of the bus 1-3 supply, and then transferring the RCPs off the bus 1-2 supply. The procedure directs the operator through the following sequential actions: (i) verify power level is below P-7; (ii) verify control power available and open indications are present on breakers 309-1A and 309-1B; (iii) place the control switch for 309-1A in the close position and hold; (iv) observe breaker 3T-1A open and breaker 309-1A close (within about 1 second); (v) release the 309-1A control switch - return to neutral; and (vi) perform the steps for the 309-1B breaker.

Licensee and inspector review determined the following sequence of events on March 28.

- the first attempt to swap Bus 1-1A occurred at 9:36 p.m. with plant load at about 12 MWe;
- the operator placed the control switch for breaker 309-1A to close;
- breaker 3T-1A opened as required, but breaker 390-1A failed to close, resulting the in the loss of bus 1-1A;
- Bus 1-1A was immediately powered from bus 1-3 and plant electricians were requested to help investigate the breaker problem;
- Breaker 309-1A was racked out by an operator, visually inspected for alignment and no obvious problems were noted; the breaker was racked in and a second attempt was made;
- plant load was increased to 21 MWe in observance of the power band in step 6.3.8 to have load between 20 and 30 MWe;
- operators stabilized reactor power just below 6% on NI power, noting that the P-7 block was in (block enabled);
- the operator placed the control switch for breaker 309-1A to close at 10:27 p.m.;
- breaker 3T-1A opened as required, but breaker 390-1A failed to close, resulting the in the loss of bus 1-1A; the P-7 interlock cleared, enabling the "at power" trips. The reactor scrammed on loss of reactor coolant flow; and
- Bus 1-1A was immediately powered from bus 1-3 and the operators entered procedure E-0 to respond to the trip.

The cause of the March 28 reactor trip was the failure of breaker 309-1A. The most likely cause of the breaker failure was that the closing springs were not charged. A summary of the licensee's root cause investigation for this equipment failure is summarized below.

The licensee concluded that NOP 2.1.6 contributed to the reactor trip by creating an operating envelope that was overly tight. NOP 2.1.6 was changed to allow the operator more latitude in selecting the generator load to complete the transfer, and thereby provide more margin to the P-7 trip setpoint. The licensee identified a procedure compliance issue when the operating crew did not follow the requirements of NOP 2.1.6 when the first transfer attempt was made at 9:36 p.m. The operating crew kept power below the P-7 setpoint by maintaining load outside the specified load band. The crew should have addressed the conflict between the NOP requirement and margin to the P-7 setpoint by processing an procedure change to NOP 2.1.6. The trip might have been averted had the procedure issue been corrected. These issues were addressed along with management expectations for performance during shift briefings on the events, and in a memorandum dated March 29, 1994.

Maintenance Troubleshooting Activities

On March 29, the inspector observed maintenance electricians troubleshoot the 4.16 kilovolt breaker 309-1A. The electricians removed the breaker from its installed cubicle and repeatedly charged and discharged the breaker closing springs. The licensee identified no failure to charge the closing springs.

CYAPCo concluded that the most probable cause of failure was that the breaker closing springs failed to operate. The basis of this probable failure mode is that the control room operator who racked the breaker in and out did not detect the noise of the spring. Maintenance electricians early on March 29, did not hear the spring discharge when the breaker was removed from its installed cubicle prior to trouble shooting. CYAPCo generated a controlled routing for breaker 309-1A to investigate the DC motor brushes during the next refueling outage. The basis of the assignment was due to an incomplete root cause description. On March 29, the PORC approved re-start of the unit based on the identifying the most probable cause of the breaker failure, and the procedural change to NOP 2.1.6.

Conclusions

The inspector noted the cause to the reactor trip was the failure of breaker 309-1A. The most probable cause of breaker 309-1A failure was the failure of the closing springs to operate. The cause could not be replicated during maintenance troubleshooting activities. Procedure NOP 2.1.6 contributed to the reactor trip creating an operating envelope that was restrictive. The operating crew should have addressed the conflict between the NOP requirement and the reactor protection system interlock. The inspector also noted all safety systems responded as designed after the reactor trip and operators took prompt actions to terminate a plant cooldown.

2.4 Engineered Safety Feature System Walkdown

Objective

The inspectors conducted a walkdown of the component cooling water (CCW) system to independently verify the status of the system. Although not included in the plant's technical specifications. the Updated Final Safety Analysis Report (UFSAR) section 7.3.1 lists CCW as an engineered safety feature (ESF) system based on its auxiliary support system function. The CCW system is important to safety since its operability is necessary during plant operation for the operation of the reactor coolant pump (RCP) thermal barrier heat exchangers and oil coolers, charging pump oil coolers, residual heat removal (RHR) pump seal water heat exchangers and RHR heat exchangers.

The inspectors verified system operability through reviews of valve lineups, control room indications, equipment conditions, and design documents and drawings. Outstanding tags and trouble reports were reviewed. The inspectors compared valves listed in the procedures and drawings with the physical plant. The inspectors also reviewed breaker alignments to verify power supplies supported system operability. The system configuration was verified in the shutdown and at power lineups.

Walkdown

The inspectors performed a walkdown of all accessible parts of the system. This included loads in the primary auxiliary building, containment, and the residual heat removal (RHR) pit. During the walkdown, valve and breaker lineups, equipment conditions, and instrumentation calibration and indications were inspected.

The inspectors used as guidance for the system walkdown normal operating procedure (NOP) 2.6-1, "Component Cooling Water System Operation," and control room and nuclear system operator logs. The inspectors also reviewed the temporary modification log, status of trouble reports on the system, and any outstanding equipment tag-outs on the system during the walkdown.

The inspectors verified normal system flowrates and component temperatures during the walkdown. Specifically, the inspectors verified that flowrates to the drain cooler heat exchanger, thermal barrier heat exchanger, non-regenerative heat exchanger, and component cooling water heat exchanger were below design values and within recommended procedural values. The inspectors verified that the component cooling water radiation monitor (R-17) reading was below the setpoint, and the alarm setpoint was based on 10 CFR 20 liquid release limits.

During the system walkdown, the inspectors identified minor housekeeping deficiencies. The following items were identified: tygon tubing attached to the 'A' and 'C' pump drains, inconsistent application of vent valve caps, apparent body-to-bonnet valve leakage from valves CC-V-707B and CC-V-708A, no valve labels on the surge tank sample valve (CC-V-774) and the component cooling water slip stream filter drain valve (C-V-774), and the installation of temporary fire detection instrumentation for the reactor coolant pumps. The housekeeping deficiencies were discussed with the licensee at the end of the inspection period.

The system walkdown noted four active trouble reports (TRs) on components in the CCW system. The oldest outstanding TR was initiated in mid-1992 for air tubing not attached to a support for a air-operated temperature control valve (CC-TV-1411). One other trouble report concerned a pin-hole leak in the service water line downstream of the 'B' CCW heat exchanger. This section of pipe has been scheduled for replacement in the proposed system-of-the-month maintenance outage in May, 1994. The service water line is a non-QA class of pipe and the heat exchanger is currently isolated.

The inspectors did not identify any outstanding temporary modifications, or equipment tagouts during the system walkdowns.

Maintenance Program

The inspector reviewed ten preventative maintenance procedures associated with components in the CCW system. The inspector evaluated the maintenance history on selected relief valves, pumps, heat exchangers, and check valves in the system. The maintenance history review was conducted between 1988 until the present. The inspection considered completion of the maintenance activities, ratio of preventative maintenance to corrective maintenance, and the identification of any trends in increased or repetitive corrective maintenance for components.

During this maintenance program review, the inspector noted that the three CCW pumps have extensive corrective maintenance. The corrective maintenance is primarily related to pump seal leakage. The recurrent seal leakage was previously addressed by replacement of seals, implementation of a new seal design under a plant modification, and use of the pump vendor to provide expertise in the installation of the seals. As of the system walkdown, two outstanding trouble reports exist on the 'A' and 'C' CCW pump seals for leakage. In February, 1992 the maintenance engineer identified recurrent seal leakage problems in the quarterly component trend reports. The engineer requested site engineering to evaluate the adequacy of the seal design and make recommendations on acceptability of seal leakage. The engineering actions were still outstanding at the end of the inspection period. The inspector did not identify any safety issue on pump seal leakage that would require immediate engineering disposition, since the leakage has not resulted in system performance degradation, nor has the leakage affected surrounding safety related components.

The inspector identified that a previous maintenance work order identified a wrong model number during routine testing of the reactor coolant pump thermal barrier relief valves. Specifically, maintenance workers in late 1989 identified that relief valves CC-RV-724A, -

724B, -724C, and -724D were Crosby model JRB versus model number JB-25-B. The inspector reviewed the applicable procedure MA 9.5-33, "Crosby Models JB and JO Safety Relief Valve Testing and PM," and noted it still identified the model number for the relief valves as JB-25-B. CYAPCo initiated MCR #94-0012 to develop and implement a procedure for model JRB that will ensure proper frequency and testing of the four relief valves. Based on discussions with maintenance personnel, the inspector noted the inspection and testing performed in 1989 under the old procedure was still valid since adjustment between the two relief valves is identified.

The inspectors concluded that the preventive maintenance programs were up to date, and the number of preventive maintenance to corrective maintenance ratios were very high.

Surveillance Program

The inspectors verified that the licensee's inservice inspection (ISI) program includes testing of the CCW pumps. Parameters monitored include motor and pump vibration, discharge pressure, and motor current. In addition, motor current analysis is performed as part of the licensee's predictive maintenance program. The 'C' CCW Pump has exhibited higher vibration levels than the other pumps. The licensee plans to perform visual inspection of the pump impeller and housing as well as oil analysis during the next refueling outage based on reliability centered maintenance suggestions. The CCW pumps show no sign of degradation.

The inspectors verified that the licensee has performed eddy current testing (ECT) on the CCW heat exchangers approximately every 18 months as part of the ISI program to determine tube degradation. The inspectors verified that 2.6% of the tubes in the 'A' heat exchanger and 1.6% of the tubes in the "B" heat exchanger are plugged. The heat exchangers were originally designed to remove 20 million Btu/hr. With the relatively low number of tubes plugged, and periodic measurements of the overall heat transfer co-efficient, the heat exchangers are capable of transferring heat removal loads. The licensee currently monitors CCW heat exchanger performance on a quarterly basis using engineering procedure (ENG)1.7-128, "Component Cooling Heat Exchanger Performance." This procedure contains specific acceptance criteria for the heat exchanger's performance based on service water flow, inlet and outlet temperatures, and CCW inlet and outlet temperature.

The CCW system includes a slipstream filter to remove particulate matter. This improves heat transfer capabilities and minimizes the buildup of activated corrosion products. The filter is designed to be replaced when differential pressure reaches 30 psid. The inspector verified that the licensee replaces the slipstream filter at appropriate intervals.

The inspectors identified the essential safety related loads served by CCW including the RHR pump seal water heat exchangers, the RHR heat exchangers and the charging pump oil coolers. Each of these loads is served by a back-up, redundant heat removal means. Consequently, the CCW system could be lost during an accident without the loss of function of any other safety related equipment.

Control Room and Local Indications/Operator Actions

The inspectors performed a review of the emergency operating procedures (EOP) and abnormal operating procedures (AOP) to determine required operator actions in various scenarios. Several required operator actions involving CCW were identified. The inspector found operator knowledge was good regarding completion of these actions.

The inspectors noted the following parameters are monitored during normal operation:

CCW surge tank level
Neutron shield tank level
CCW heat exchanger outlet temperature
CCW total flow
CCW pump amps
CCW suction temperature
Service water temperature and pressure for each CCW heat exchanger
CCW discharge pressure
CCW flow and temperature from RCS drain cooler
CCW flow and temperature from RCP thermal barriers
CCW flow from RCP seal water heat exchanger
CCW flow through non-regenerative heat exchanger
CCW slipstream filter flow and differential pressure

Based on their review of these procedures, the inspectors determined the EOPs and AOPs could be completed using the given instrumentation.

Plant Information Report Review

The inspectors performed a review of past plant information reports (PIR) involving CCW to evaluate the licensee's resolution of each issue. PIR 92-033 documented a failure of CC-CV-225B to pass the required flow for the acceptance criteria of surveillance procedure 5.7-152. A procedural inadequacy was found, and the procedure was modified to change the valve lineups during the flow test.

PIR 92-104 documented findings regarding containment isolation valves CC-SOV-608 and CC-TV-1411 which are required to operate in a harsh environment. These valves were not included in the master list for equipment qualification. This item was identified in NRC inspection report 50-213/92-10.

PIR 91-112 documented a spurious actuation of annunciator EE-1-2 "HCP Override LD-TV-230." Shortly thereafter, CC-TV-917, CCW supply to NST cooler containment isolation valve, was found closed. The licensee's root cause evaluation found that the cause of the alarm was a defective signal state switch on the annunciator driver circuit card for annunciator EE-1-2. The spurious annunciator actuation was considered to be separate from the found closed condition of CC-TV-917. Surveillance procedure SUR 5.7-93A "ISI testing of CCW and NST cooler trip valves," performed two days prior to finding CC-TV-917 closed, verified adequate valve performance.

The inspectors found the licensee's PIR followup to be timely and appropriate given the safety significance of each issue.

Chemistry Controls

CYAPCo adds potassium tetraborate and potassium nitrite into the CCW system as corrosion inhibitors. The sampling program evaluates the nitrite concentrations providing an indicator of corrosion inhibitor within the CCW water. The sampling program is performed on a weekly basis.

The chemistry sampling program also evaluates iron ions, and pH of the water as a diagnostic tool to determine if service water has been introduced into the system. The basis for identifying if service water has been introduced into the system is the judgement of the chemistry personnel based on the trends of iron ions and the pH of the CCW system.

The sampling program is also designed to detect the introduction of reactor coolant water into the CCW system by primarily looking at trends in tritium and gamma activity. CYAPCo believes that tritium analysis is a beneficial isotope to review due to its long half life, abundance in the reactor coolant system, and the ability to monitor leakage during reactor shutdown conditions (i.e., residual heat removal heat exchanger is in service). Other non-radioisotopic indications of reactor coolant water leakage into the system are pH decrease, nitrite ion decrease, and surge tank level increase.

The inspector reviewed the chemistry logs for the CCW system since May, 1993. The inspector noted an increase in average tritium levels between May, 1993 through February 1994 of approximately three fold in the system. The average values in May, 1993 were 4.17E-3 microcuries/milliliter to an average value of 11.72 E-3 microcuries/milliliter in February, 1994. The reactor coolant system tritium valves have also increased by approximately a factor of 3 from .644 microcuries/milliter to 1.85 microcuries/milliliter. The inspector will follow CYAPCo actions in quantifying RCS leakage into the CCW system **(IFI 94-05-01)**.

Response to NRC Information Notice 93-92

The NRC issued Information Notice (IN) 93-92, "Plant Improvements to Mitigate Common Dependencies in CCW Systems," to alert licensees to potential problems resulting from common dependencies in CCW systems. The dependencies on loss of CCW were found to be contributors to core melt frequency at several nuclear power plants.

The Northeast Utilities Service Company (NUSCo) Probablistic Risk Assessment (PRA) section evaluated the impact of loss of CCW system on the core melt frequency for the Haddam Neck plant and concluded that the plant is not vulnerable to loss of CCW events leading to core melt, and the overall contribution to core melt frequency due to loss of CCW is negligible. Based on the above, CYAPCo does not plan any design or procedural changes based on the information from IN 93-92. The inspector independently verified that the system dependencies of CCW have available back-ups, and based on a review of the IPE concluded that loss of the system is not a significant contributor to core melt.

Conclusion

Overall, the inspector concluded, the CCW system is maintained in a good operational status. Engineering support to the surveillance program was good. The inspector determined no significant maintenance activities or temporary modifications exist that would affect operation of the system. The inspector also noted operator understanding of the system was good.

3.0 MAINTENANCE (61726, 62703 and 71707)

3.1 Maintenance Observation

The inspectors observed various corrective and preventive maintenance activities for compliance with procedures, plant technical specifications, and applicable codes and standards. The inspectors also verified appropriate quality services division (QSD) involvement, appropriate use of safety tags, proper equipment alignment and appropriate use of jumpers, proper radiological and fire prevention controls, appropriate personnel qualifications, and adequate post-maintenance testing. Portions of activities that were reviewed included:

- **Installation of Spray Shields**

The inspector reviewed activities in progress on March 18 to install spray shields around the newly installed service water pipe in the "A" diesel generator (EDG) room. The work was controlled per AWO 94-02255 and CMP 8.5-121, "Installation of Hilti Kwick Bolts, Hilti Kwick Bolt II, and Drop-In Concrete Anchors." The spray shields were part of the modifications to the service water system installed per plant design change record (PDCR) 1462.

The new service water piping was routed to the EDG skids by running the piping in the overhead in the engine rooms and the electrical bus rooms. The purpose of the spray shield was to capture any leakage from the overhead SW piping, which otherwise would impact the emergency safeguard buses. The spray shield was mounted around and concentric with the overhead SW piping in both the engine and electrical bus rooms. The new spray shield was supported by its own deadweight supports and was fabricated from light weight stainless steel tubing.

The inspector observed activities in progress to install the shield supports in accordance with Step 6.3 of CMP 8.5-121. The inspector determined the procedural controls were met and personnel were knowledgeable of the procedure requirements. The work package was complete and properly approved. No inadequacies were identified.

- **Replacement of Emergency Diesel Generator Air Solenoid**

On March 15, the inspector observed a maintenance electrician prepared for a preventive maintenance activity to replace the 'A' emergency diesel generator air start solenoid. The electrician was performing a pre-job walkdown. As part of the walkdown, the electrician was verifying part numbers of the installed air solenoid, and the replacement solenoid. The electrician noted a difference between the solenoids. The installed solenoid was General Motor model number 9081134 whereas the replacement was model number 712-015. The maintenance electrician stopped the maintenance activity, and presented the issue to his supervision and the system engineer.

Subsequent CYAPCo investigation determined that the wrong model number of the replacement air solenoid was the result of an error by a procurement engineer on a replacement item evaluation (RIE). Based on the approval of the RIE, the licensee stocked the warehouse with model 712-015 diesel air solenoids. RIE CYOE-93-0124 was completed on June 3, 1993, and was as a result of a supplier deviation notification. The supplier deviation notification was prompted by a 10 CFR 21 report issued on June 14, 1990 by the vendor (MKW Power Systems). The 10 CFR 21 report documented a failure of solenoid part number 9513134 because the valve's coils spring did not contain sufficient force to keep the valve closed in a 200 psig air system. The licensee initially did not receive or take action in response to the 10 CFR 21 report, in part, because the licensee had model number 9081134 instead of the part number 9513134.

The difference between part number 9081134 and 9513134 was a manual override feature to start the engine without 125 volt DC power to energize the solenoid. The supplier deviation report stated that part number 712-015 has a larger spring co-efficient than part number 9513134 to overcome leakage when used in a 200 psig air system. The error by the procurement engineer was a failure to pursue the difference in part numbers. The procurement engineer did review the Bill of Materials sheet for the installed solenoid valve. The initial purchase order was returned to CYAPCo because the vendor (MKW Power Systems) did not supply this model (9081134) any longer. The vendor stated that replacement for this model number was 712-015.

Nuclear Engineering & Operations (NEO) procedure NEO 6.12, "Evaluation of a Replacement Item," step 6.3.3 states that the RIE specify the original and alternate item's description, including technical and physical characteristics, and also state the reason for the evaluation. Further, the procedure states in order to properly perform an RIE, the engineer will need copies of, or access to sources of information such as, but not limited to, the following: manufacturing catalogs, vendor technical manuals, and equipment specifications. The error in RIE CYOE-93-0124 was that the original model number specifications were not identified properly.

On March 18, 1994, the system engineer dispositioned the model 9081134 solenoid against the 10 CFR 21 report even though the specific model number identified was not installed in the emergency diesel generator air system. The evaluation concluded acceptability of the "installed" solenoid valves based on no signs of detectable leakage by the valve, air compressors are not constantly cycling, and no indication of air pressure degradation. The bounding significance of the issue, as stated by the evaluation was that this deficiency would not render the emergency diesel generator inoperable, but result in more air usage by the air system. The installed solenoid valve was left in the system. At the end of the inspection period, CYAPCo was preparing a RIE to replace the air solenoid with model 712-015. CYAPCo was considering a modification to the model 712-015 solenoid to eliminate the manual override feature.

Conclusion

The inspector determined the maintenance electrician displayed good attention to detail in identifying the replacement emergency diesel generator air start solenoid had a different model number. He also appropriately stopped work and raised the issue to management. The inspector noted procurement engineering incorrectly dispositioned RIE CYOE-93-0124 by not properly describing the installed solenoid. This issue is unresolved pending NRC review of RIE's processed in accordance with the requirements of procedure NEO 6.12 **(UNR 94-05-02)** to ensure this is not a programmatic problem .

- **Main Steam Trip Valve Testing**

On March 24, while the plant was in cold shutdown, the inspector observed maintenance personnel stroke time test the main steam trip valves. The valve strokes were to determine the minimum torque values on the valve's packing gland. The mechanics loosened the packing, wetted down the shaft, and performed numerous valve strokes. The various valve strokes were performed to prevent a failure of the valve to open within the acceptance criteria of SUR 5.1-77, "Main Steam Line Isolation Trip Valve Functional Test." The stroking activity was to determine if the valves required maintenance prior to the performance of SUR 5.1-77 in a hot standby condition. The main steam trip valve's safety function is to close within ten seconds. The inspector did not identify a specific safety function for valve opening time. During the observation of the surveillance, the inspector did not identify any deficiencies with the valve meeting the close stroke acceptance criteria.

The inspector expressed concern for repeated stroke time tests of the steam trip valves to prevent failure of the valves during the performance of SUR 5.1-77 in hot standby conditions. The inspector was concerned that repeated strokes of the valves could result in disc or seat damage during cold pipe conditions since there was no "cushioning" effect from steam. Also, the inspector was concerned that the packing adjustments left in the "hand-tight" condition after the test could result in excessive steam leakage during plant heat-ups. At the end of the period, the licensee was evaluating the most appropriate time to perform this surveillance test. This is an inspector follow item (IFI 94-05-03).

3.2 Surveillance Observation

The inspectors witnessed selected surveillance tests to determine whether: frequency and action statement requirements were satisfied; necessary equipment tagging was performed; test instrumentation was in calibration and properly used; testing was performed by qualified personnel; and, test results satisfied acceptance criteria or were properly dispositioned. Portions of activities associated with the following procedures were reviewed:

- **SUR 5.1-152, Service Water System Alignment**

The inspector reviewed the service water (SW) system on March 26 to verify the system was properly aligned to support plant operation. The inspector noted that the licensee had completed the valve lineup prescribed by SUR 5.1-152 on March 23 to assure the SW system was aligned for restart.

During his review on March 26, the inspector noted that a blank copy of the SUR 5.1-152 checklist taken from a file in the control room was incomplete. The procedure consists of nine pages, and pages 5 through 9 are the valve lineup checklist for the SW system. The inspector noted that page 9 of 9 was missing. Page 9 listed four SW pump casing vent isolation valves located in the intake structure that are required to be verified open. The vent valves are normally open to allow a slip stream of water to be drawn from the upper casing area to remove entrained air. The inspector identified this discrepancy to the duty shift supervisor.

The shift supervisor checked the remaining file copies of SUR 5.1-152 and noted three were complete and page 9 was missing from two copies. The shift supervisor directed the auxiliary operator to immediately perform another SW system valve lineup verification using a complete version of SUR 5.1-152. The supervisor also called in Operations support staff to the plant to retrieve the official record copy of the SUR from the operations office to verify the status of the checklist when completed on March 23. The system valve lineup was promptly completed, which verified that the system valves, including the pump casing vents, were in the proper position. The shift supervisor directed that operators check other surveillance procedures currently in use for plant startup to be checked for completeness, and he initiated a PIR to document the event for further follow up.

Licensee review noted that the official record copy of SUR 5.1-152 was performed on March 23 without page 9. Thus the position of the vent valves were not checked as required on that date. The performance of the procedure with an incomplete copy of the SUR demonstrated poor attention to detail by the auxiliary operator. Further, the review of the completed surveillance by the duty shift supervisor on March 23, and by the Operations Manager on March 25 failed to note the discrepancy.

The shift supervisor determined on March 26 that the four SW vent valves are also checked for proper position as part of procedure NOP 2.1-24 when each service water header is aligned for service. NOP 2.1-24 was performed on March 7 for the south SW header, and on March 14 for the north SW header. The inspector verified that the file copies of the completed checklists were complete and properly signed off. Thus, although the SW valve lineup had not been satisfactorily completed using the intended SUR, the licensee did have a QA record showing satisfactory verification of the proper valve lineup.

The licensee initiated further actions on March 26 to review the administrative processing and distribution of procedures kept on file in the control room. The inspector completed a sampling review of completed surveillances on file in the control room and in the operations support area. No further discrepancies were identified regarding the work completed to support the startup. However, the operations support staff began a more systematic and thorough review of other completed surveillances and procedures to verify they were satisfactorily completed. Other minor discrepancies were noted in the completed records, but none what would impact the proper verification of system operability. Finally, the licensee initiated actions to review the administrative and supervisory approval of completed surveillance procedures.

Licensee actions continued at the conclusion of the inspection period. This item is considered unresolved pending completion of licensee actions to address the concerns described above, and subsequent review by the NRC (**UNR 94-05-04**).

- **ENG 1.7-65, Hydrostatic or Pneumatic Pressure Test**

On March 1, the inspectors observed the performance of ENG 1.7-65, "Hydrostatic or Pneumatic Pressure Test." The hydrostatic test was performed on the service water header supply to the 'B' emergency diesel generator. The supply header was relocated under plant modification PDCR 1462, "CY Service Water Piping Replacement/Reroute to the Emergency Diesel Generators."

Prior to the hydrostatic test, the inspectors independently verified the tagging boundary. The hydrostatic test was completed successfully, and no deficiencies were noted in the tagging boundary. The inspectors determined the quality services department inspection of the welds was thorough, with the QA inspector verifying each weld twice.

- **SUR 5.7-148B, Substantial Service Water Flow**

On March 7, the inspectors observed the performance of SUR 5.7-148B for the 'C' and 'D' service water pumps. The inspector noted the surveillance acceptance criteria were met and the surveillance procedure was adhered to by the technicians.

- **SUR 5.7-205, Inservice Testing of Main Steam Safety Valves MS-SV-14, 24,34,44 Remote/Actuated Solenoid Valves**

The inspector observed the activities in progress on March 26 to test the main steam safety valves. The test was performed with the reactor in Mode 4, with main steam pressure at about 195 psig. The purpose of the test was to demonstrate the valves could be operated in the relief valve manually from the control room. After preparing for the test, plant operators test each valve in sequence by operating the control board switch for the safety valve actuation solenoid. The valves are open for 10 seconds, as test personnel stationed at the valves verify proper lift and closure.

The inspector observed portions of the test both from the control room and locally at the valves. The inspector confirmed that test prerequisites and initial conditions were satisfied, and that operators and test personnel followed the procedure. The inspector determined the operators performed well communicating and coordinating with maintenance and engineering personnel. The procedure controls were met and personnel were knowledgeable of the test requirements. All four valves tested satisfactory and were verified operable to support plant startup. No inadequacies were identified.

- **'A' Auxiliary Feedwater System Hydraulic Pressure Switch Calibration**

On March 26, the inspector observed the performance of surveillance procedure (SUR) 5.5-128, "Train A AFW Pump Low Hydraulic Pressure Switch Calibration." The surveillance was performed by I&C specialists under authorized work order (AWO) 94-03048. The surveillance data for the hydraulic pressure switches met the acceptance criteria. The inspector noted during the test, that technicians had difficulty calibrating pressure switch PS-3A1 due to spatial limitation in the hook up of the leads across the switch terminal block. The technicians recommended to the I&C engineer that a procedural change be processed in the future to take voltage readings at the disconnect panel versus locally across the switch contacts. The inspector plans no further follow-up of the performance of SUR 5.5-128.

- **Spent Fuel Pool Bulk Water Temperature Test**

On March 17, the inspector observed portions of special test (ST) 11.7-137, "Spent Fuel Pool Bulk Water Temperature Test." The objective of the special test was to obtain spent fuel pool (SFP) heatup and cooldown data to support the future SFP rerack project. The inspector reviewed the test exceptions, locations of the data loggers, and instrumentation calibrations. All activities reviewed were acceptable.

As part of the special test, CYAPCo implemented bypass jumper 94-0014. The jumper was to provide for a fire hose connection from the SFP heat exchanger to the boron recovery overhead condenser. The purpose of the jumper was to provide a temporary service water supply to the SFP heat exchangers during a maintenance activity to replace the stagnant leg service water piping to both the 'A' and 'B' SFP heat exchangers. The jumper was required to be installed if unexpected delays were encountered during service water pipe replacement and/or if the pool temperature exceeded 110 degrees Fahrenheit (°F). During the inspection period, the jumper was not installed; however, heat-up of the pool resulted in a recorded temperature of 132°F on March 22 at 1:09 a.m. The Updated Final Safety Analysis Report (UFSAR) section 9.1.3.1 states that 140°F is the cooling system design limit. Based on discussions with the shift supervisor, the inspector learned the jumper was not installed since the replacement service water piping was installed and available; however, the post-modification testing was not completed. CYAPCo cooled the SFP back down using NOP 2.10-1, "Spent Fuel Pit Cooling System Operation," on March 22.

The inspector reviewed the technical and safety evaluation for jumper 94-0014. The technical evaluation considered "burst" pressure of the fire hose, flowrate through the fire hose, and flooding of the area in the event of a potential break. The safety evaluation reviewed accidents resulting from a loss of SFP cooling, and a loss of service water. The inspector found the evaluations were complete and accurate.

4.0 ENGINEERING AND TECHNICAL SUPPORT (71707)

The inspectors reviewed selected engineering activities. Particular attention was given to safety evaluations, plant operations review committee approval of modifications, procedural controls, post-modification testing, procedures, operator training, and UFSAR and drawing revisions.

4.1 Replacement of Service Water Piping

The inspector reviewed licensee actions during this period to assess the cause of degradation in service water system piping and welds, and to replace the piping in certain safety related portions of the system. The inspector reviewed in particular those actions the licensee had committed to perform prior to restart of the plant, and as documented in a letter to the NRC staff dated February 22, 1994. This area was reviewed during a past inspection and NRC follow up issues were tracked under item **(94-03-04)**. A meeting between the NRC and CYAPCo staffs occurred in the NRC Region I Office on March 16 to further the NRC review of this topic. A copy of the handout summarizing the CYAPCo presentations during the meeting is provided as Attachment A to this inspection report.

Inspection and Evaluation of the degraded Welds and SW Pipe

The licensee completed examinations and engineering evaluations during the outage to assess the causes for the piping and weld degradations and to identify what corrective actions were needed to address the causes. The examinations included the use of radiography, chemical sampling and visual examination of open piping systems. The examinations were completed with the assistance of an outside consultant having experience with microbiologically influenced corrosion (MIC) and piping system corrosion mechanisms. The licensee obtained additional samples to identify the presence of live biological specimens.

The evaluations were performed for various portions of the service water system, including stagnant and low flow subsystems, as well as continuous flow subsystems. The objective of the evaluation was to "bound" the corrosion problem by identifying the areas most susceptible to MIC, and to identify the areas requiring immediate action (pipe replacement) to address degraded conditions.

The licensee found active MIC sites in the piping systems and confirmed that piping degradation occurred in the stagnant lines and near the junctions where stagnant headers branched off the main headers. The areas selected for pipe replacement were those showing the most degradation.

The inspector observed piping sections removed by the licensee from various locations within the SW system in support of the piping modifications and an evaluation of the "as-found" degraded conditions. The licensee selected 23 weld and pipe sections for detailed analysis by the NU materials laboratory. The materials selected were deemed the most degraded and similar to weld #21 and #22, which were previously removed and evaluated in detail. The inspector concluded that the defects he observed were bounded by the degradation in welds #21 and #22. The licensee intends to include the results of the evaluation of the worst case piping conditions as part of his final operability assessment of the SW system. The operability assessment was scheduled to be complete by June 1, 1994. NRC review of this issue was in progress at the end of the inspection period.

Completion of Modifications to the SW System

Based on the examinations and evaluations described above, the licensee implemented piping modifications under plant design change record (PDCR) 1462 to replace selected portions of the service water system at Haddam Neck. The major portions of the SW system affected by the modifications included: both supply headers to the emergency diesel generators, from the branch connections up to the engine skids; both supply headers to the residual heat removal heat exchangers, from the branch connections up to isolation valves (MOVs 5 and 6); the bypass lines on the Adams filters; the normally stagnant line in the intake screen house providing the cross connection between the service water and the fire water systems; and, the supply and return lines to the plate heat exchanger in the spent fuel pool cooling system.

The modifications included the abandonment in place of the piping buried underground or behind block walls in the diesel generator rooms. The new supply piping was routed to the EDG skids by running the piping in the overhead in the engine rooms and the electrical Bus rooms. The new piping was supported by deadweight and seismic supports. During the preparation of the safety evaluation supporting the modifications, the licensee determined that the piping runs in the overhead above 4KV safeguard Buses 8 and 9 created the potential for an unreviewed safety question (USQ).

The USQ was created by a new failure introduced by the overhead piping, wherein postulated SW leakage could fall upon and adversely impact the emergency safeguard buses. To address this issue, the licensee modified the design to include a spray shield that was mounted around and concentric with the overhead SW piping in both the engine and electrical bus rooms. The spray shield was fabricated from light weight stainless steel tubing, which was sealed at the joints between successive lengths of tubing. The spray shield was drained to the engine room to allow for periodic monitoring of the piping status during routine operator tours, and to allow collection of any leakage in the area where a sump and float switch arrangement would detect the accumulation of water in the room.

The modifications were completed and the new pipe sections were verified acceptable through the completion of a satisfactory hydrostatic test prior to plant restart. The inspector noted that the licensee identified and addressed several deficiencies that occurred while implementing the modifications, including a problem with the issuance of the wrong type of weld wire and the failure to reinstall a dead weight support in the 'B' EDG room. The inspector determined the licensee corrective actions were timely and appropriate.

The inspector reviewed the implementation of the modifications throughout the inspection period, and verified the adherence to established administrative and work controls. The inspector identified no inadequacies in the scope of the modifications performed, or in the implementation of the design change. NRC review of the modification under PDCR 1462 were in progress at the end of the inspection period.

Development of a MIC Mitigation Program

The licensee developed a MIC mitigation program as described in the following engineering Procedure ENG 1.7-131, "CY Microbiologically Influenced Corrosion (MIC) Prevention, Monitoring and Mitigation Program." The procedure was issued for implementation on March 30, 1994. The program is deemed applicable to all portions of the service water system, including stagnant and low flow subsystems, intermittent flow subsystems, and continuous flow subsystems. The program is also applicable to the fire water system.

The program included actions to monitor susceptible piping for MIC degradation and mitigate continued degradation. The program includes provisions for chemical treatment of the process flow streams to mitigate MIC, monitoring of process flow stream hydraulic performance, and periodic inspection of the piping systems. NRC review of the licensee's implementation of the MIC program was in progress at the end of the inspection period.

Completion of the Third Party Evaluation

The licensee performed a third party evaluation in accordance with the CYAPCo letter to NRC dated February 22, 1994 and the commitment (page 6) to perform a third party root cause analysis of how the SW event was handled by CYAPCo. The charter of the task force was to review the management and engineering decision making process on how the SW issue was handled, from the time the first sample was obtained until the NRC became involved. The task force (TF) defined the time of substantial NRC involvement to be on or about February 2, 1994.

The task force completed a review over a three week period and presented findings in an exit meeting with Haddam Neck management on March 24, which was attended by site management and the Director of Quality Assurance (QA). The inspector attended the exit to evaluate the licensee's self assessment process. The formal task force report was scheduled to be issued after the end of the inspection period.

The task force presented two (draft) reports, a "majority" and a "minority" report. The author of the minority report declined to endorse the majority findings. He did not disagree with any of the facts or events presented by the majority, but at times offered a different perspectives on the facts. The task force provided a detailed summary of the facts and events on how the SW leak was handled beginning in March 1993 when the leak occurred and the actions to process a relief request under generic letter GL 90-05 were initiated. Numerous inadequacies were identified in how the SW issue was handled. The findings show weakness in the process for dispositioning the plant information report (PIR) and the nonconformance report (NCR) for the initial leak on March 8, in the technical review of the leak, and in the engineering and plant management oversight of the issue. The majority task force presented the following four findings which constituted causes for the inadequate engineering and management decision making process:

- Less than adequate (LTA) evaluation of the generic implications of the March 8 leak;

- LTA peer and management review of the technical issue; there was an over reliance on the judgements of a single engineer, the system engineer;

- LTA integration of support and specialty services, such as inadequate coordination with the stress analysis and materials engineering. This deficiency worked both ways - the site engineer did not fully communicate with NUSCo and the support groups did not pursue the issue; and,

- LTA documentation of the bases for engineering judgements, decisions and conclusions.

The minority report findings were also presented at the exit meeting, which included eight observations supporting an alternate view regarding the circumstances on how the SW issue was handled, starting from the response to the March 8, 1993 leak, up to the issuance of the February 22 letter to the NRC. During the exit, QA and CYAPCo management discussed the need for additional work to follow up on the findings of both reports, and to further develop the root causes for these findings on program weaknesses.

The licensee informed the inspector on March 25 of the following additional actions that would be taken as a result of the task force findings:

- An additional third party review would be performed to review the issues raised by the minority report. The review would be conducted by personnel independent of the site and NUSCo engineering. The results of the review will be made available to the NRC when completed, which was expected to occur by May, 1994.

- To address the TF findings regarding the weaknesses in the manner in which the PIR for the March 8 weld leak was closed out, the licensee conducted an expedited review of all PIRs for the last two years. The review was performed during the period of March 25 - 27 by a group of NUSCo engineers assembled at the Haddam Neck site. The group focused on those PIRs having potential operability issues. The review verified that the issues were handled properly; i.e., there was a adequate basis to support how the issues in the PIR were dispositioned. This action was completed prior to plant restart.

  The inspector completed a preliminary review of the results of the PIR assessment prior to plant restart on March 31. No inadequacies were identified in the licensee findings. NRC review of this matter was in progress at the end of the inspection period.

No substantially new or different facts were revealed from the task force effort not already known to the inspector. The inspector's review of the task force majority and minority reports were in progress at the end of the inspection period. The NRC findings regarding this licensee self-assessment effort will be described in a future inspection report.

Accuracy of Information in the February 22 Letter to the NRC

During NRC staff reviews of the SW issue, the licensee committed on February 3 to submit on the docket the results of his examinations of the SW piping, along with a description of the basis for his operability determination, the long term plans to replace affected portions of the SW system, and the program to address MIC. This information was provided to the NRC in letter (B14755) dated February 22, 1994. The information in the February 22 letter to the NRC was reviewed by the inspector and was found generally accurate relative to the facts and chronology of actions to address the SW issue.

However, the licensee's independent task force presented its findings in an exit meeting with site management on March 24 and provided questions regarding some of the information in the February 22 letter. The questions were summarized in a list of 14 comments on the February 22 letter. Three additional comments were subsequently provided by other NU personnel who reviewed the letter for accuracy. The NU Nuclear Licensing (NL) Supervisor contacted the inspector on March 23 and reported that NL was also in receipt of the comments. Licensee actions were in progress at the end of the inspection period to review the comments. The licensee stated that the comments would be addressed and that factual errors would be corrected on the docket by a subsequent letter, as needed.

The inspector reviewed the comments in the context of the letter and assessed each one based on his knowledge of the SW issue and how it developed. The inspector concluded that some of the comments did not constitute errors of fact; some comments relate to statements that might be incomplete in the context of the paragraph quoted, but would not be considered inaccurate by a person knowledgeable of the SW issue; and, some comments (two) might describe errors of fact. If the factual errors were substantiated, the errors would be considered minor. In reviewing the significance of the comments, the inspector assessed whether the information in the letter as written would have materially affected the NRC staff's assessment of the SW issue and CYAPCo's performance, or alter the NRC staff's response to the SW issue. In all cases, taken individually and collectively, the inspector determined the comments did not affect the NRC assessment of the SW issue.

In summary, licensee actions were in continuing at the end of the inspection period to meet commitments as described in the February 22 letter, including: the reassessment of the response to Generic Letter 89-13, and the performance of a SWOPI. The licensee reported this matter to the NRC as licensee event report (LER) 94-02, dated March 10, 1994. In the LER, CYAPCo stated actions are in progress to evaluate the worst case flaws identified in the SW piping and to finalize the operability determination for the SW system. The operability evaluation and the results of the safety assessment of the event would be provided in a supplemental LER by June 1, 1994. NRC review of this area was in progress at the end of the inspection period. NRC follow of this matter continues to be tracked by inspection item **(94-03-04)**.

4.2 Motor Control Center Number 5 Bus Transfer Failure

A failure of the motor control center number-5 (MCC-5) automatic bus transfer (ABT) device occurred during functional testing conducted on February 16, 1994 when the reactor was shutdown. This test was developed by the licensee in response to a similar failure on

June 27, 1993, because the root cause of that failure had not been positively identified and because of the importance of this device. In each case, operator actions were required locally in the switchgear room to re-energize the MCC.

The recent failure led to re-examination and discovery of a defect in a 480 volt supply breaker associated with the ABT. A snap-ring was found not properly located on a shaft of the breaker operating mechanism. This allowed the shaft to move and come in contact with the breaker trip bar. The operating mechanism was replaced with a new assembly and the breaker operated normally. Additionally, the licensee modified the bus transfer device control circuit through a design change with the intention of improving its overall reliability. The modified design was tested thoroughly prior to returning it to service.

Refer to NRC Report 94-03 for further NRC reviews of this issue. A meeting between the NRC and CYAPCo staffs occurred in the NRC Region I Office on March 16 to further the NRC review of this topic. A copy of the handout summarizing the CYAPCo presentations during the meeting is provided as Attachment A to this inspection report.

Failure Investigation and Troubleshooting

The licensee developed a troubleshooting plan in accordance with authorized work order CY 94-01445 to investigate the ABT failure. Test instrumentation was installed to monitor the ABT control circuit and special test ST 11.7-126 was repeated with a spare circuit breaker replacing the breaker that failed to close in bus-6 position 11C. The ABT performed with no anomalies; a troubleshooting plan was then developed for the circuit breaker that had been in service in position 11C. This was the same breaker in service in that position during the June 27, 1993 test.

The licensee conducted visual inspections of the 11C, DB-25 breaker components on February 19, 1994. During visual inspection of the mechanism linkage the licensee identified the manual operating shaft was not properly positioned. A snap-ring intended to hold the shaft in position was not properly located in the snap-ring slot. This allowed the breaker manual closing cam at the end of the shaft to contact the trip linkage. The improper position of the snap-ring interfered with the breaker trip linkage.

The licensee was able to demonstrate that a slight inward movement and counterclockwise rotation of the manual closing shaft tripped the breaker. The snap-ring being improperly located would cause the breaker to have intermittent failures. This may have allowed the breaker to function properly for several cycles. By observation of dust on the lubrication of the manual closure shaft, it appears that the snap-ring was mispositioned for quite some time.

It appears that if the snap-ring was properly positioned in its groove, it could not jump out of the groove. This was confirmed by measurements taken by the licensee. The one-half inch diameter manual operating shaft and its machined groove were close to dimensions supplied by Westinghouse. The licensee found that with an internal diameter of 0.470 inch, the snap-ring had expanded slightly from a new ring free diameter of 0.451 inch. The inspector concluded that the snap-ring was most likely mispositioned during maintenance.

The Westinghouse representative stated that the snap-rings are sometimes removed to facilitate lubrication of the breaker components, in this case a shaft Bushing located just beyond the snap-ring groove. However, neither detailed procedures were available for maintenance of the breaker operating mechanism (and specifically the manual closing shaft and snap-ring) nor were details of these components included in the vendor instruction manuals.

A post maintenance test of the ABT including the associated circuit breakers was conducted on February 22. During this test, power was supplied to MCC-5 by jumper from 480 volt Bus 4. This configuration allowed for ABT testing that did not cause voltage transients in the MCC. With the jumper in place and energized, the two normally closed breakers located in MCC-5 that are fed by the ABT breakers, were both opened. The ABT was operated through multiple cycles while selected to either bus as the preferred power source. For purposes of the test, loss of power to the safeguards 480 volt buses was simulated by operation of test switches wired into the potential transformer circuit that powers the time delay relays. Initially during the test, the failed 11C breaker was replaced with a spare. Following full testing with the spare, the repaired 11C breaker was returned to its Bus 6 position. Although the breaker successfully operated during the ABT test, a momentary direct current ground in the breaker closing circuit caused the testing to be suspended. The breaker closing coil (52CC) was replaced to correct the problem.

The inspector reviewed the technical and safety evaluation that supported the use of the temporary power jumper for MCC-5. As part of that effort, the licensee established procedures to power the MCC from Bus 4, and to restore power to the MCC from the ABT at the conclusion of testing and also for emergency actions to be taken in the event of a loss of power to Bus 4. The inspector also reviewed these procedures, attended the PORC meeting approving the procedures, inspected the jumper configuration for possible plant equipment and personnel safety concerns and observed the ABT testing.

A records search for this same circuit breaker found that during preventive maintenance overcurrent tests on February 21, 1986, the breaker malfunctioned and tripped free (reference AWO CY 85-05887). The maintenance technicians found the same snap-ring out of position and replaced it. This was observed and documented in a quality assurance surveillance report that was annotated with a recommendation for follow-up, which apparently was not pursued. This was the same circuit breaker that had been in Bus-6 position 11C during both the June 27, 1993 and the February 16, 1994 tests.

The licensee initiated a formal failure analysis of the ABT failure. Although a significant amount of work in the analysis was performed, the final report was not complete by the end of the inspection period. However, based on conversations with the licensee, the inspector does not expect that there will be a great deal of new information offered in the final report.

Modification to the MCC-5 Automatic Bus Transfer Control Logic

Following the discovery and repair of the circuit breaker deficiency, the licensee installed a modification to the ABT control logic. The modification had been developed to improve the reliability of the circuit in that there will be fewer demands for circuit breaker operation. Work on the modification had been initiated following the ABT failure on June 27, 1993 under plant design change PDCR 1434.

The inspector reviewed both the original and revision 1 of the design change document, and observed portions of the installation and post-modification testing. The inspector found that the installed design would generally meet the goal of reducing the number of circuit breaker operations and had simplified the control circuit. Although the actual number of breaker cycles taking place during a transient depends on both the initial conditions and the postulated electrical transient scenario, these changes should reduce the number of breaker operations and therefore improve the overall reliability of the MCC-5 power source. The modification changed the concept of ABT operation by removed the preferred power source selector switch. Although the licensee intends to normally align the MCC-5 power supply to 480 volt safeguards electrical Bus-5, the ABT will not automatically transfer between energized sources. Bus-5 was selected because its associated 'A' electrical division normally has less of an electrical load than the 'B' division associated with Bus-6.

As modified, the ABT logic will trip the normally closed supply breaker (9C) from Bus-5 when power is lost to Bus-5 (approximate bus voltage of 240 volts) for one second, only if Bus-6 is energized (approximately bus voltage of 480 volts). As the Bus-5 supply breaker (9C) opens, the Bus-6 supply breaker (11C) will close and a control room annunciator (G-1-2-9 Upper) will alarm "MCC-5 Transfer to bus 6." If power is not available to either Bus-5 or -6, the circuit breakers will not change state unless power is restored to Bus-6 first. Loss of power to the MCC will alarm a control room annunciator (G-1-2-9 Lower) "MCC-5 Loss of Voltage." If a transfer to Bus-6 does occur, the ABT will not transfer back to the Bus-5 supply unless power is lost from Bus-6.

If the ABT was aligned to its alternate supply from Bus-6, a loss of Bus-6 voltage for 0.75 second will cause its supply breaker (11C) to trip open and the supply breaker (9C) from Bus-5 to close. If power is available to Bus-5 first, the circuit breakers will remain in this alignment. If Bus-6 was re-energized first, the supply breaker (9C) from Bus-5 will trip open and the supply breaker (11C) from Bus-6 will re-close. This breaker logic is determined by the time delay relay drop out time settings. It applies to the presence of 480 volt bus voltage without regard to its source, off-site power or the emergency diesel generators.

The modified logic was preoperationally tested to confirm these sequences. A jumper supplied power to MCC-5 from Bus-6 during those tests to eliminate the undesirable effects of voltage transients on MCC-5 loads. Following the preoperational test, the normal alignment for Buses-5 and -6 and MCC-5 was re-established and the ABT was functionally tested per special procedure ST 11.7-126, Revision 2.

The modified design was observed to have a weakness that under certain conditions will require operator action locally in the switchgear room to restore power to MCC-5. Both supply breakers may end up in the trip-free state after attempting to close simultaneously. For this to occur, both breakers (9C and 11C) would have to have opened during a loss of power to both safety divisions and then both Buses would have to be re-energized simultaneously. This was demonstrated during preoperational testing at the inspector's request. The licensee's position on this event is that because of the ABT design and electrical system operation, this is very unlikely. The inspector confirmed that procedures were in place to direct operator actions needed to re-energize MCC-5 in the event that this occurs.

Conclusions

The failures of the MCC-5 ABT apparently resulted from unauthorized circuit breaker maintenance activity performed incompletely and without detailed procedures and quality assurance checks. The failure mechanism rendered the MCC-5 supply from Bus 6 unreliable for as long as the defective circuit breaker was in service. Additionally, corrective actions were not taken following discovery of the same deficiency on February 21, 1986. These practices illustrate a lack of sensitivity in the past by licensee personnel for the importance of MCC-5 to reactor safety.

The ABT modification should improve overall reliability because it will reduce the number of operational demands placed on the circuit breakers. Procedures are in place to direct operator actions in the event of a loss of power to MCC-5. These procedures are appropriate considering the nature of the ABT modification.

The assessment of the safety significance of this event is described in licensee event report (LER) 94-04, as summarized in Section 5.3 of this report. The licensee performed a root cause evaluation of the MCC-5 ABT failure, and of the previous root cause evaluation that was completed in the July of 1993. The immediate corrective actions completed by the licensee prior to returning the plant to power operation included the replacement of the Bus 6 breaker 11C manual operating mechanism, verifying that the snap ring was in place on other breakers, and implementing a modification to simplify the MCC-5 design and to make its operation more reliable.

The inspector concluded CYAPCo staff performed well to investigate the ABT failure during this inspection period. Licensee corrective actions were appropriate and timely. The licensee stated that a supplemental LER would be submitted by June 1, 1994 to provide the results of the root cause evaluation, and to describe additional long term corrective actions.

NRC concerns in this matter are tracked by open Inspection Item **(94-03-04)**. NRC reviews are in progress to determine what additional actions may be warranted to address weaknesses in licensee programs that resulted in repetitive ABT failures.

4.3 Potential Containment Sump Recirculation Boundary Leakage

Event

On March 8, the licensee identified a previously unreviewed monitored offsite release pathway during the emergency core cooling sump recirculation phase of injection. Sump recirculation pathway is implemented to continue to inject borated water into the reactor core during a postulated loss of coolant accident (LOCA) using the containment sump as a source of inventory instead of the refueling water storage tank.

A CYAPCo system engineer was evaluating a design basis motor-operated valve calculation for charging header stop valves (CH-MOV-292B and CH-MOV-292C) and identified that the calculated pressure of the charging header could exceed the setpoint of the metering pump discharge relief valve (CH-RV-280) when performing the manipulations directed in the emergency operating procedure ES-1.3, "Transfer to Sump Recirculation."

The licensee documented the issue in plant information report (PIR) 94-042. Based on the department head discussion of the PIR, the Unit Director decided to assign a five working day reportability evaluation as proscribed in administrative control procedure (ACP) 1.2-16.1, "Plant Information Report." On March 15, at approximately 8:17 a.m., the licensee reported the event pursuant to 10 CFR 50.72 (b)(2)(iii)(c) to the NRC:Operations Center.

Background

In 1986, CYAPCo developed plant modification PDCR 854, "Long Term ECCS Modifications." During the performance of LOCA analyses for the Integrated Safety Assessment Program (ISAP), the licensee discovered a range of postulated small breaks in the reactor coolant system loop 2 cold leg which could not be adequately mitigated by high pressure recirculation using the residual heat removal (RHR) pump and a charging pump. While performing initial design work to correct this issue, CYAPCo identified another scenario involving a break in the low pressure safety injection system core deluge line for which sufficient emergency core cooling system delivery in the sump recirculation mode could not be assured. In April, 1986 the NRC approved an exemption from single failure criterion 10 CFR 50 Appendix A, criterion 35. The exemption was for cycle 14 operations. PDCR 854 was installed to eliminated the single failure vulnerability in the emergency core cooling system. The modification installed a cross-tie between the RHR and high pressure safety injection (HPSI) systems so that during sump recirculation the RHR pump can take suction from the containment sump and feed the suction of the HPSI pump for high pressure sump recirculation. The modification also replaced the existing core deluge manual valve with a motor operated valve to permit remote and redundant isolation of core deluge to mitigate a core deluge line break. During the 1987 refueling outage, the mechanical piping system modification was performed, and during the 1989 refueling outage, the installed motor-operated valves were connected to safety related power.

The inspector learned that revision 7 to ES-1.3 in 1990 isolated the charging system by closing valves CH-MOV-292B and CH-MOV-292C. The EOP action was to limit the charging pump flow when the charging pump is being used during sump recirculation (i.e., off-site power is available). Charging pump flow limiting is necessary to prevent exceeding the normal flow capacity of the RHR pumps. Specifically, the total HPSI and charging flow is maintained less than 2,200 gallons per minute (gpm).

The metering pump discharge relief valve (CH-RV-280) is subjected to charging pump header pressure in the system alignments performed under ES-1.3. The setpoint of the relief valve is 2,735 psig +/-3%. CYAPCo performed an analysis that calculated charging header pressure at 2,658 psig, which is within the -3% of the relief valve. The radiological release path from CH-RV-280 is to the primary drains tank to the waste gas surge header, until the relief valves (WG-TV-1156C or VH-SV-1171) open on the waste gas surge tank. If the waste gas compressors continued to operate, the waste gas decay tanks would eventually fill and pressurize. Pressure in the tanks would increase until the relief/trip valve WG-TV-1160A3 or B3 or C3 setpoint of 215 psig. Both relief valves from the waste gas surge tank, and the waste gas decay tanks discharge to the main stack.

Inspection

The inspector review of this issue included the prior opportunities to discover this vulnerability, independently calculating charging header pressure, review of revisions to ES-1.3, evaluating the extent of CYAPCo corrective actions, verifying CYAPCo calculations with actual plant conditions for charging header discharge pressure, evaluating other potential radiological releases in recirculation phase of injection, and the timeliness of the reportability determination.

The inspector focused on opportunities to discover this vulnerability back to the modification work under PDCR 854, and the EOP revisions associated with this modification. The project engineer stated that the original concept of the design did not consider the use of charging pumps but rather this function was maintained to ensure reactor coolant pump seal cooling during a postulated LOCA. The design review did identify a vulnerability in the metering pump suction relief; however, did not identify the vulnerability associated with the discharge relief. A Plant Operations Review Committee (PORC) meeting on March 23, 1994, concluded that current procedures for modifications were sufficient to have identified this vulnerability. The PORC requested the engineering design department to review lessons learned from this modification with the design engineers.

The inspector independently calculated the expected charging pump discharge pressure in ES-1.3 and it agreed with that of the CYAPCo system engineer. Inspector review of revision 8 to ES-1.3 noted it incorporated the necessary operator actions from PDCR 854; however, it did not consider potential radiological consequences of CH-RV-280.

On March 22, the inspector verified good agreement with the calculated charging pump header pressure, and the actual header pressure in a shutdown condition. The alignment of the charging system in a plant shutdown condition is identical to that in ES-1.3. The header pressure as recorded in the control room was 2,650 psig which compares to the calculated value of 2,658 psig. The relief valve was not open; however, the inspector concluded this configuration places the potential for lifting the metering pump relief during normal plant shutdown conditions.

CYAPCo corrective actions for this event included a revision to ES-1.3 prior to Mode 4 operation. The procedural change was to check one charging pump running, then stop the pump by placing its control switch in trip-pullout, and closing valves CH-MOV-292B and C. The technical evaluation for this procedural change concluded that no credit is taken for charging water to the RCP seals in the safety analysis. This change was deemed acceptable since stopping the charging pump in the recirculation phase of a postulated LOCA was not any different that a LOCA without offsite power.

CYAPCo evaluated other portions of the charging system potentially vulnerable to unwanted lifting of a relief valve a potential release point. The licensee identified two other relief valves (metering pump suction relief, and RCP return seal water relief), that potentially could be exposed to charging header pressure. The inspector noted that the relief valves are isolated in ES.13 prior to shutting the charging header isolation valves. The inspector independently confirmed that the licensee's evaluation was complete and accurate by reviewing the piping and instrument drawings of the chemical and volume control system.

The inspector evaluated CYAPCo's decision and basis for use of the ACP 1.2-16.1 step 1.5.2. This procedural step allows the Unit Director to check the reportability status uncertain and initiate a engineering reportability screening not to exceed five working days. In this case, the engineering screening did not exceed five working days. Based on discussions with the system engineer assigned the reportability screening, he reevaluated the assumptions previous identified, and solicited additional information from the Operations department, and NUSCo radiological assessment branch (RAB). The system engineer confirmed with operations the potential relief path, and discussed with RAB the potential radiological consequences. The radiological consequences were concluded by CYAPCo to be not significant due to "scrubbing" of radionuclides, and the cooling of the sump water by the RHR heat exchanger not resulting in flashing of the sump water. The system engineer during this time frame, confirmed that the first potential indication of the relief valve lifting would be the main stack radiation monitor (R-14B) levels increasing. Based on the above reviews by engineering for the reportability screening, the inspector concluded that the time for reportability was reasonable.

Conclusion

The inspector concluded that the system engineer displayed a good questioning attitude in identifying a postulated deficiency in the emergency operating procedures during his review of an MOV calculation. A prior opportunity for discovery of the vulnerable CVCS line-up was the modification review in 1987. The inspector determined CYAPCo took appropriate corrective actions.

4.4 Service Water Throttle Valve Adjustments

Inspection Scope

The inspector reviewed CYAPCo actions to verify service water flow balances to safety-related components. The review was performed because of the extensive modifications to the service water piping, and the changes of hydraulic system resistance. Two specific flowrate measurements were verified by the inspector. The measurements were for the containment air recirculation fan coolers, and for the residual heat removal heat exchanger.

Results

Procedure ENG 1.7-107, "Service Water System Throttle Valve Setting for SW-V-264, 266, 268, and 270," was performed on March 23, 1994 under authorized work order (AWO) 9402905. The inspector's review of the surveillance data concluded that the flow from all four service water return valves from the containment air recirculation coolers met the acceptance criteria for flow and the valve co-efficient (Cv).

CYAPCo contracted Westinghouse Electric Corporation to evaluate the need to perform service water flow testing to the residual heat removal heat exchangers. A Westinghouse letter to CYAPCo dated March 4, 1994 concluded that no post-modification flow test was required. The contractor's basis was that the piping replacement was "one-for-one," and worst case computer modeling uncertainty could be approximately 9%. CYAPCo testing to validate the computer modeling in 1990 concluded that the flowrates were within 2% of the computer model. CYAPCo did not perform flow testing to the residual heat removal heat exchangers based on the Westinghouse recommendation.

The inspector reviewed the maintenance history on the two outlet throttle valves (SW-V-250A and SW-V-250B) for the residual heat removal heat exchanger since 1990. The review was to identify if the valves have been repositioned affecting their valve co-efficient. Based on the work order description, the inspector concluded that "positive" valve position controls were exercised for corrective maintenance activities.

In conclusion, CYAPCo, either by contractor engineering basis support or in-situ testing, was able to confirm that appropriate service water flows existed to safety-related components. The inspector had no further questions on this issue.

5.0 PLANT SUPPORT (40500, 71707, 90712, and 92701)

5.1 Radiological Controls

During routine inspections of the accessible plant areas, the inspectors observed the implementation of selected portions of the licensee's radiological controls program. The inspectors reviewed utilization and compliance with radiation work permits (RWPs) to ensure that detailed descriptions of radiological conditions were provided and that personnel adhered to RWP requirements. The inspectors observed controls of access to various radiologically controlled areas and the use of personnel monitors and frisking methods upon exit from those areas. The inspectors verified posting and control of radiation areas, contaminated areas and hot spots, and labelling and control of containers holding radioactive materials were in accordance with licensee procedures. The inspectors determined that the health physics technician control and monitoring of these activities were good.

5.2 Oversight Review Committee Meetings

The inspectors attended several Plant Operations Review Committee (PORC) meetings. The inspectors verified technical specification 6.5 requirements for member attendance were met. The meeting agendas included procedural changes, proposed changes to the Technical Specifications, Plant Design Change Records, and minutes from previous meetings. PORC meetings were characterized by frank discussions and questioning of the proposed changes. In particular, consideration was given to assure clarity and consistency among procedures. Items for which adequate review time was not available were postponed to allow committee members time for further review and comment. The inspectors determined that the committee closely monitored and evaluated plant performance and conducted a thorough self-assessment of plant activities and programs.

The inspector also observed the March, 1994 Nuclear Review Board meeting held at the unit. Based on his observations of the meeting, the inspector concluded that board members probed and questioned the technical completeness of proposed technical specification changes. Good interactions were noted on items carried forward from previous board meetings.

5.3 Review of Written Reports

Periodic and Licensee Event Reports (LERs) were reviewed for clarity, validity, accuracy of the root cause and safety significance description, and adequacy of corrective action. The inspectors determined whether further information was required. The inspectors also verified that the reporting requirements of 10 CFR 50.73 and Technical Specification 6.9 had been met. The following reports were reviewed:

- **LER 93-19, Incorrect Action Statement Applied to Inoperable Fire Door**

The licensee reported this event as a condition prohibited by technical specifications. On December 13, 1993 at 6:57 p.m., a fire door which separates the turbine building upper level from the service building access hallway was declared inoperable due to damage to the door. An hourly fire watch patrol was established in accordance with technical specification 3.7.7. On December 17, CYAPCo determined that a continuous fire watch was required since no fire detection and/or suppression systems were located adjacent to the affected door. CYAPCo performed a programmatic review of all fire doors to identify which require an hourly or continuous fire watch when declared inoperable. The licensee identified nine (9) fire doors that would require a continuous instead of previously implemented hourly fire watch if they were inoperable.

For the inoperable fire door, the licensee's corrective action consisted of establishing a continuous fire watch on December 17, and the issuance of a TS clarification to plant operators. The inspector verified the completion of the corrective actions.

No violation will be issued since, in accordance with the NRC Enforcement Policy in Section VII.B. of 10 CFR 2, Appendix C, the violation was identified by the licensee, it was classified as a severity level IV, it could not be prevented by corrective actions from a previous violation, and licensee corrective actions were appropriate. This LER is closed.

- **LER 94-02, Service Water System Inoperable Due to Pipe Flaws**

This LER described the February 12, 1994 plant shutdown after a pin hole leak developed on the service water (SW) supply piping to the 'A' diesel generator (EDG). Since the leak was on the first weld upstream of the manual isolation valve and failure of the line would also affect the supply to the 'B' EDG, the plant operators conservatively declared both service water headers inoperable. The plant entered the action statement for Technical Specification 3.0.3 and was shutdown and in Mode 5 on February 13, 1994.

The leak developed as the weld was undergoing light surface grinding in preparation for ultrasonic testing. The testing was part of an evaluation to assess structural integrity of pipe welds affected by microbiologically influenced corrosion. The corrective actions were to replace the degraded weld, and to investigate the remainder of the safety related portion of the service water system for susceptibility to the corrosion mechanism. Portions of the SW piping supplying the EDGs and the residual heat removal exchangers were replaced, along with section of piping associated with the Adams filters and the cross-tie with the fire water system.

NRC review of this issue is documented in NRC Report 94-03 and in Section 4.0 above. The licensee stated that the results of the root cause analysis and the operability assessment of the SW system with the degraded welds would be provided in a supplemental report by June 1, 1994. The inspector reviewed LER 94-02 and noted it was complete and accurate in all material respects. In particular, the LER did not contain the inaccuracies identified in CYAPCo's February 22, 1994 letter to the NRC. Since NRC concerns are tracked under Inspection Item 94-03-05, and supplemental LERs will be reviewed during future routine inspections, this LER is considered closed.

- **LER 94-03, Containment Personnel Hatch Failed Leak Rate Test**

The licensee reported per 10 CFR 50.73(a)(2)(i) an event involving plant operation in a condition prohibited by the technical specifications, in that the integrity of the containment air lock was not demonstrated within 72 hours of a containment entry.

On Tuesday, February 8, 1994, with the plant at full power, the licensee performed a containment entry. At 11:14 a.m. on February 8, the licensee completed the containment entry and exited technical specification (TS) 3.6.1.3. TS 4.6.1.3(a), Containment Air Locks, requires the licensee to demonstrate the operability of the containment air lock within 72 hours of each closing by verifying no greater than 0.01 L_a (54 lbm/day) from pressure decay or other equivalent method when the volume between door seals is pressurized to greater than or equal to 10 psig for at least 15 minutes.

On February 10, 1994, the licensee performed surveillance procedure SUR 5.1-62A, "Personnel Hatch Reduced Pressure Leak Test," to satisfy the requirements of TS 4.6.1.3. The procedure provides the operator with the option to complete the surveillance using the volumetric leak rate monitoring or pressure decay method. Volumetric leak rate monitoring involves measuring the air flow required to maintain the airlock at a given test pressure. This air flow is equal to the airlock leakage. Using pressure decay, the air lock is pressurized, initial and final pressure and temperature readings are taken. The air lock leakage rate is calculated using the two pressure readings. The volumetric leak rate monitoring method gives accurate, instantaneous results which are temperature independent.

During the test on February 10, 1994, the operator used the pressure decay method to test the access hatch. Following a period of thermal equalization, the initial pressure and temperature readings were taken. The pressure and temperature readings were taken again after a 60 minute period of pressure decay. The pressure inside the hatch dropped from 11.71 psig to 11.62 psig. Using the initial and final pressures, the operator calculated the leakrate to be 0.0013 psig/min, which was less than the limit of 0.0025 psig/min. The test was deemed satisfactory since the acceptance criteria was met. The procedure in effect at the time did not require that the operator compensate the final pressure reading for the temperature changes.

The results of the procedure were forwarded to Inservice Inspection (ISI) Engineering. On February 17, 1994, while reviewing the test results, the ISI engineer noted the temperature increase during the test from 47.2° F to 47.8° F. The

ISI engineer recalculated the leakrate by adjusting the final pressure reading to account for the temperature increase. The calculated temperature compensated leak rate was 63.564 lbm/day, which is in excess of the TS limit.

The ISI engineer notified Operations of the recalculated leakage rate. Operations inspected the hatch seals in the as found condition and re-performed SUR 5.1-62A using the volumetric leak rate monitoring method. The hatch seals were found to be undamaged and the measured leak rate was 1475 sccm, which is within the TS limit of 2830 sccm. The February 17 test results were deemed more indicative of the actual leak tightness of the air lock due to its superior test method. In addition, a temporary procedure change was implemented which added a step to the procedure requiring the pressure decay test to be repeated if a temperature change occurs.

Safety Significance

The air lock door seals were inspected in the as found condition and found to be undamaged. In addition, when SUR 5.1-62A was performed on February 17, the air lock leakage was within the acceptable range. Consequently, the event is regarded to be of low safety significance.

Since the ISI Engineering followup calculations found the airlock leakage to be in excess of the TS limit, the airlock was considered to be inoperable from the time of the containment exit at 11:14 a.m. on February 8, 1994. With the containment airlock inoperable, the action statement for TS 3.6.1.3(b) requires the licensee to maintain at least one air lock door closed and either restore the inoperable air lock to operable status within 24 hours (11:14 a.m. on February 12, which includes the 72 hour allowance to perform the surveillance and complete the ISI review) or be in at least hot standby (Mode 3) within the next 6 hours (5:14 p.m. on February 12) and in cold shutdown (Mode 5) within the following 30 hours (11:14 p.m. on February 13). As a result of service water inoperability, the plant was in hot standby at 3:21 p.m. on February 12 and cold shutdown at 6:16 p.m. on February 13. Thus, the TS limiting condition of operation was met even if the actual air lock leak rate is assumed to be the results obtained by ISI on February 17.

Corrective Actions

The inspector observed the licensee review of this event when it was discovered. The licensee concluded that the TS surveillance requirements were not met because the final test results, including the calculations by ISI to demonstrate compliance with the leak rate limits, were not completed within the 72 hour period to prove the operability of the air lock. Further, the licensee concluded that the root cause of the test failure was a deficient test procedure, and that the excessive delay in performing the review by ISI was unacceptable. Corrective actions were taken accordingly.

The licensee is modifying SUR 5.1-62A and the procedure changes include: completion of SUR 5.1-62A within 48 hours of closing the hatch; ISI engineering followup calculations to be completed within the following 24 hours; and, explicitly state that volumetric leak rate monitoring is the preferred means of performing SUR 5.1-62A, and to use pressure decay if the volumetric leak rate monitoring equipment is not available.

On Tuesday, March 22, during a meeting of the Plant Operations Review Committee (PORC), the event was discussed as well as the corrective actions. The licensee decided to perform a thorough review of all operations procedures which required an engineering followup calculation as part of an operability determination. These procedures will be modified, if necessary, to ensure that operability determinations are made within the required time period.

Findings

The inspector identified no deficiencies in the licensee's response to this event. Corrective actions were appropriate and timely. Nonetheless, the failure to complete the test of the air lock within 72 hours was a violation of Technical Specification TS 4.6.1.3. Licensee engineering and management demonstrated a high regard for the containment test requirements, and the need to address personnel performance and procedure issues. Thus, no violation will be issued since, in accordance with the NRC Enforcement Policy in Section VII.B of 10 CFR 2, Appendix C, the violation was identified by the licensee, it was classified as a Severity level IV, it could not be prevented by the corrective action from a previous violation, and the licensee corrective actions were appropriate.

- **LER 94-04, Automatic 480 Volt Bus Transfer Failure**

With the plant in cold shutdown in Mode 5 on February 16, the automatic Bus transfer scheme for motor control center (MCC-5) failed when tested per special test ST 11.7-126. The cause of the failure was identified to be a mispositioned snap ring (a mechanical retaining device) mounted in the manual operating shaft of the Bus 6 breaker 11C. The mispositioned snap ring made operation of the ABT unreliable, such that switching MCC-5 to Bus 6 as a source of power could not be assured in all instances. Although the exact time when the snap ring became mispositioned was not identified, it is likely that the condition existed for a time in excess of the 72 hour actions statement of Technical Specification 3.8.3.1.2 during past operation of the plant at power. The licensee reported this event as a condition prohibited by the technical specifications and reportable under 10 CFR 50.73(a)(2)(1)(B). Further NRC review of this issue is described in Inspection 94-03, and in Section 4.2 above.

Safety Significance

The licensee's assessment of this condition was provided in the LER. A postulated single failure could have resulted in the loss of power to MCC-5, and the inoperability of certain safety systems whose function is important to mitigate certain design basis accident conditions. However, throughout Cycle 18, the Bus 5 was selected as the preferred power source for MCC-5 and both diesel generators were operable. Thus, the safety function of MCC-5 would have been provided by power from Bus 5. All testing of the Bus 5 supply to MCC-5 has been successful to date. Additionally, emergency procedures existed to direct operator actions to restore power to MCC-5. The inspector identified no inadequacies in the licensee's assessment. Based an assessment of the event described in Report 94-03, the inspector concluded that the operation of the ABT and the supply of power from Bus 6 to MCC-5 was assured for at least one operation during Cycle 18 operation. Therefore, the safety significance of the breaker 11C inoperability was minimized.

Findings

The licensee performed a root cause evaluation of the MCC-5 ABT failure, and of the previous root cause evaluation that was completed in the July of 1993 when the ABT failed to operate as required during a test with the plant shutdown for the refueling outage. The immediate corrective actions completed by the license prior to returning the plant to power operation included replacement of the Bus 6 breaker 11C manual operating mechanism, verifying that the snap ring was in place on other breakers, and implementing a modification to simplify the MCC-5 design and to make its operation more reliable.

Following the February failure, licensee corrective actions were appropriate and timely. The licensee stated that a supplemental LER would be submitted by June 1, 1994 to provide the results of the root cause evaluation and to describe additional long term corrective actions. The supplemental LER will be reviewed during future routine inspections. No violation will be issued since, in accordance with the NRC Enforcement Policy in Section VII.B of 10 CFR 2, Appendix C, the violation was identified by the licensee, it was classified as a Severity level IV, it could not be prevented by the corrective action from a previous violation, and the licensee corrective actions were appropriate. The LER was accurate to describe the event and its significance.

The inspector concluded that CYAPCo staff performed well to investigate the ABT failure during this inspection period. NRC concerns in this matter are tracked by open Inspection Item 94-03-04. Based on the above, this LER is considered closed.

5.4 Follow-up of Previous Inspection Findings

The inspector reviewed licensee actions taken in response to open items and findings from previous inspections were reviewed. The inspectors determined if corrective actions were appropriate and thorough and whether previous concerns were resolved. Items are closed where the inspector determined that corrective actions would prevent recurrence. Those items for which additional licensee action is warranted remain open. The following items were reviewed:

(Closed) Violation 93-21-01, RHR Valve Misaligned

The inspector reviewed licensee corrective actions in response to this issue, as described in the CYAPCO letter to the NRC dated February 15, 1994. The violation involved the improper restoration of a valve following maintenance on the 'B' residual heat removal pump on October 7 and 8, 1993. RH-V-785B was part of tagging clearance 931229 to support automated work order (AWO) CY-93-12811. When AWO CY-93-12811 was completed and clearance 931229 was cleared, RH-V-785B was only opened 76% instead of the required full open position. The cause of the event was inadequate self-checking on the part of the operators performing the task. A contributing factor was the location of the valve and the length of the reach rod used to operate the valve.

The valve was correctly positioned following identification of the violation. The incident was discussed with each operating crew. Management expectations regarding personnel performance were reviewed with the shift supervisors. The event was one of several incidents of unacceptable performance which occurred during this operating period and is an adverse trend in the area of human performance (personnel errors and human factor issues). CYAPCo took the following steps to reverse the trend.

- An Operations Department Instruction (ODI) entitled "Lessons Learned" was established to capture events in which information (such as anomalies in valve operation) are provided to all crews. This log is maintained in the control room and will be reviewed monthly.

- A self-checking program was formally established. The program is entitled Stop Think Act and Review (STAR) and was presented to each operating crew during the last cycle of Licensed Operator Requalification Training. The program was formally incorporated in requalification training and is used during the weekly and annual simulator evaluation.

All of the human performance events described in the inspection report occurred in late 1993. No human performance events have taken place in 1994. The inspector concluded that the licensee actions in response to this violation are acceptable. Operator performance will be reviewed as part of subsequent routine inspections. This item is closed.

(Closed) Violation 93-21-02, Inaccurate Operator's Log

The inspector reviewed licensee corrective actions in response to this issue, as described in the CYAPCO letter to the NRC dated February 15, 1994. The licensee's response provided the following explanation for the observed violation. The Nuclear Systems Operator (NSO) responsible for performing the required fire watch signed the fire watch log in advance of actually performing the required watch. This action was, at that time, a misrepresentation of facts. However, the first fire watch round was actually performed at the time required.

The NSO was required to complete two separate procedures to ensure completion of the required fire watches. The first was Administrative Control Procedure (ACP) 1.2-2.32; "Implementation and Control of Fire Protection Program Requirements," the second was ODI #177 "Fire Watches," which was performed to ensure that no fire watch is missed. The NSO error in believing that the more important procedure was ODI #177 and that ACP 1.2-2.32 was of lesser importance. The opposite was true; ACP 1.2-2.32 is the legal record and ODI #177 is an operator aid. The NSO's confusion with regard to the relative importance of each document prompted him to complete ACP 1.2-2.32 ahead of time, as if it were an operator aid. The NSO did not realize that he was officially documenting the completion of a fire watch he had not yet performed.

The NSO received disciplinary action per CYAPCo guidelines. In addition, previous work by the NSO was checked using the security computer logs and no discrepancies were noted. All crews were briefed on this incident, and the need to maintain accurate records was emphasized. CYAPCo communicated to all Operations Department personnel how seriously the event was viewed by management, and re-enforced expectations on the need for factual information and operator integrity. The inspector concluded that licensee actions were appropriate. After this event, the licensee completed actions that eliminated to need to perform fire watches as compensatory measures in several plant areas. The satisfactory completion of fire watch rounds will be reviewed during subsequent routine inspections. This violation is closed.

(Open) Unresolved Item 94-03-04, Actions to Address Degraded Service Water System Piping

This item was open for follow up of actions to address degraded conditions in the review water system. NRC inspection of this area is also described in Section 4.1 of this report. The following actions were completed by CYAPCo as required by the commitments in a letter to the NRC dated February 22, 1994: (i) evaluation of the welds and SW piping to identify the root cause of the degradation; (ii) the replacement of SW piping to address the identified degraded conditions; (iii) the development of a microbiologically influenced corrosion (MIC) mitigation program by April 1, 1994, and, (iv) the completion a third party evaluation decision process by CYAPCo engineering and management to understand how the SW corrosion issue was handled.

The following actions were ongoing by CYAPCo at the end of this inspection period: the implementation of the MIC mitigation program; the performance of a service water operational performance inspection (SWOPI); and, a reassessment of the response to Generic Letter 89-13; which will be completed as part of the SWOPI.

In addition to the above items, this matter is open pending further NRC review of licensee actions to correct factual errors in his February 22 letter, as necessary (reference section 4.1 of this report) and resolve the third party audit issues. This item remains open pending completion of the above actions and subsequent review by the NRC.

(Open) Follow Item 93-22-04, Degradation of Spent Fuel Pool Poison Material

The inspector reviewed the status of actions on this issue with the Reactor Engineering Supervisor. Samples of both types of poison coupons from the Haddam Neck SFP, along with archive material from Millstone 1, were sent to an offsite laboratory for detailed analysis. The archive material was unirradiated and is representative of the Haddam Neck Carborundum coupons that were observed to undergo loss of material. The results of the examination of all coupon materials were reported in draft report from Northeast Technology Corporation dated March 4, 1994.

The preliminary test results include a determination of areal density derived from neutron attention measurements. The unirradiated archive material had the highest areal density of 0.1148 grams B-10/cm^2. All other samples had at least 0.10 grams B-10/cm^2, including the Carborundum sample that was identified to have lost material based on the testing conducted on site. The Carborundum coupon had the lowest areal density at 0.1066 grams B-10/cm^2. Thus, all samples met the original design specification for poison material areal density needed to assure minimum shutdown requirements are met. The results for the offsite laboratory testing were based on neutron attenuation instead of a measure of changes in coupon weights, and are deemed a more reliable indicator of areal density. Thus, the present results, if accurate, show the safety significance of the lost poison material is lower than initially assumed.

Licensee review and acceptance of the laboratory results were still in progress at the end of the inspection period. In particular, the licensee requested that the vendor include more information in the final report to describe the bases for the correlation between neutron attenuation and areal density of the coupons. Other reviews were in progress to understand the reason for the gradual loss of the Carborundum material, its significance and what corrective actions (if any) are needed to assure the SFP storage racks remain acceptable. One option includes the CYAPCo plan to modify the SFP storage racks to allow for adequate SFP storage capacity until the projected shutdown of Haddam Neck. As part of the rerack modifications, it is possible to use the racks containing the Carborundum material, without taking credit for the boron in the racks to assure minimum shutdown margins are met. This item remains open pending the completion of licensee actions to address the loss of poison material, and subsequent review by the NRC.

- **(Open) Unresolved Item 94-03-01, Pressurizer Power Operated Relief Valves**

NRC inspection report 50-213/94-03 documented the failure of both pressurizer spray valves to full stroke open. The previous inspection developed **UNR 94-03-01** to review CYAPCo actions to resolve the valve failure caused prior to entering a plant operating mode that requires the PORV's to be operable.

The inspector noted that the licensee reinstalled the "old" style diaphragm that used the BUNA-N material. The basis of installing the pre-1993 material was due to feedback from the maintenance mechanics who were uncomfortable with the replacement diaphragm position. Specifically, the "new" style diaphragm was extruding outside the flange surfaces during the torquing of the air operator cover.

The PORV's were successfully stroke time tested on March 21, 1994. The inspector considers **UNR 94-03-01** still open pending evaluation of the LER, and proposed resolution of the air system upgrade project for the PORV system.

6.0 EXIT MEETINGS

During this inspection, periodic meetings were held with station management to discuss inspection observations and findings. At the close of the inspection period, an exit meeting was held on April 19, 1994, to summarize the findings and conclusions of the inspection. No written material was given to the licensee and no proprietary information related to this inspection was identified.

In addition to the exit meeting for the resident inspection the following meetings were held for inspections conducted by Region I based inspectors.

Report No.	Inspection Dates	Reporting Inspector	Areas Inspected
50-213/94-02	3/7-3/11/94	Lusher	Emergency Planning
50-213/94-06	3/28-4/1/94	Furia	Radiological Protection

Connecticut Yankee
Atomic Power Company

Region I Meeting

March 16, 1994

ATTACHMENT A

Agenda

- Introduction — John Stetz
- MCC-5
  - Overview — Pierre L'Heureux
    - Circuit Design
    - X-Coil
  - Chronology — Pierre L'Heureux
    - RFO 17 Activities
    - Cycle 18 Activities
    - Service Water Outage Activities
  - Root Cause — Pierre L'Heureux
  - Corrective Action — Pierre L'Heureux
  - ABT Modifications — George Townsend

Agenda

- Service Water

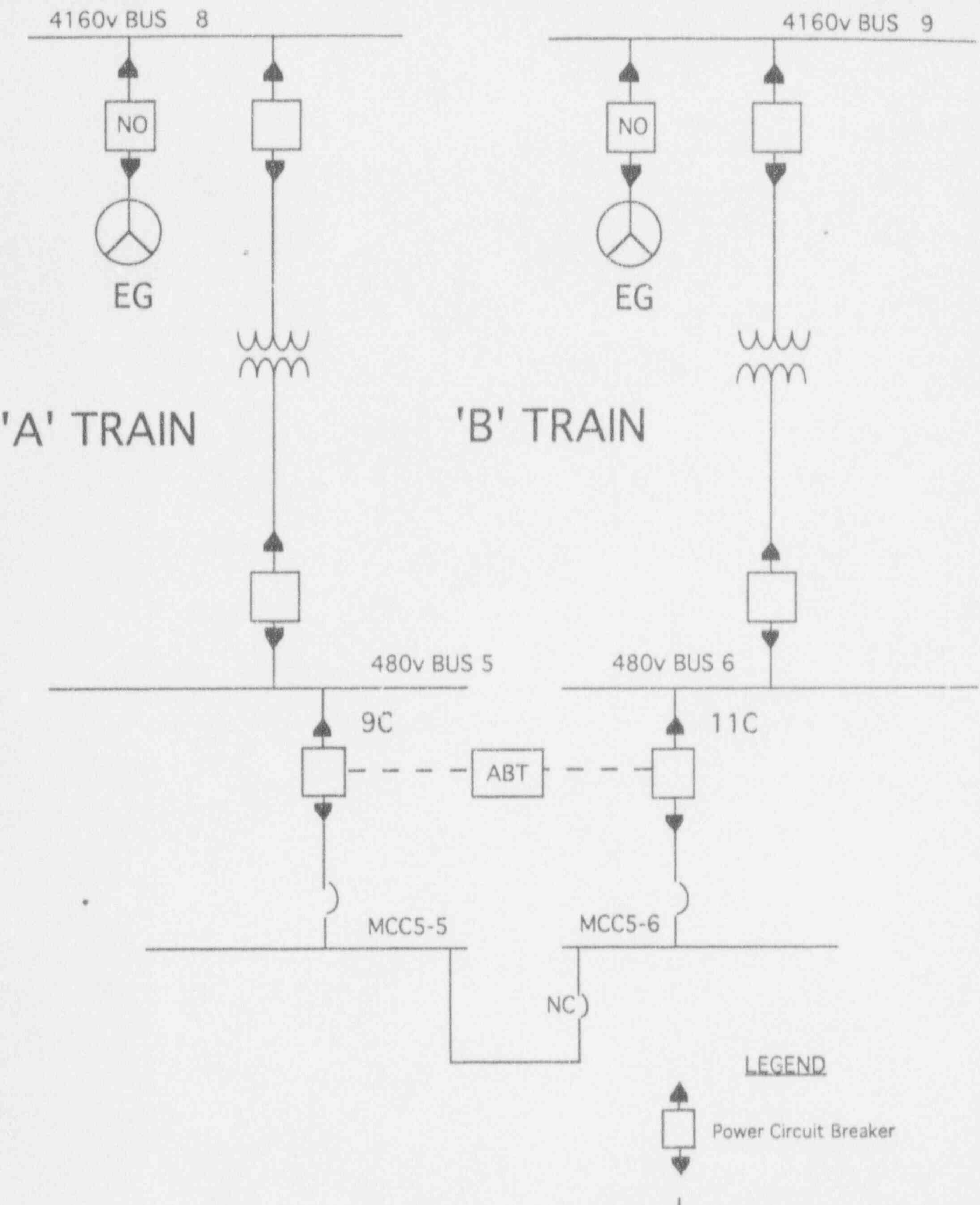
- Background	Jere LaPlatney
- System Overview	Tom Galloway
- Technical Summary	Tom Galloway
- Inspection, Repair & Replacement Activities	Tom Galloway
- Root Cause	Paul Mason
- MIC Program	Paul Mason
- Operability and Disposition Criteria	Nelson Azevedo
- Closing Remarks	Jere LaPlatney

MCC-5

Pierre L'Heureux

Circuit Design Overview

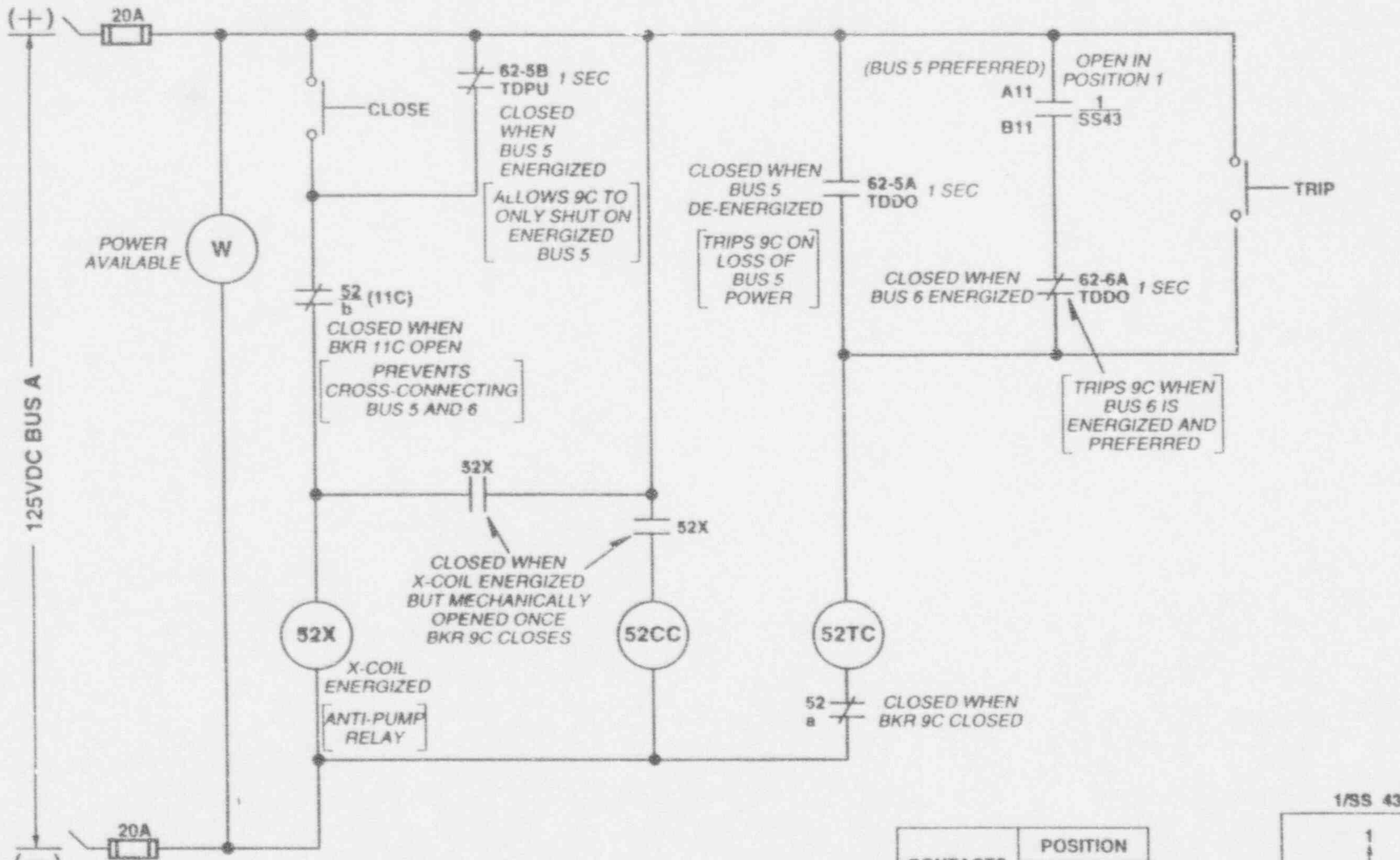
- MCC-5 May Be Powered From:
  - 'A' Train (Bus 5) or 'B' Train (Bus 6)
- Preferred Source Selector Switch (SS 43)
- Electrical Interlocks
  - Prevents Cross-Connecting Trains
  - Prevents Transfer to a Dead Bus
- 52 X Relay
  - Electrical-Mechanical Design
  - Relay Energizes and Seals In
  - Energizes Closing Coil
  - Closing Coil Mechanically Opens 52X Contacts
  - Relay Must De-Energize to Reset



MCC-5 ONE-LINE DIAGRAM

ORIGINAL DESIGN

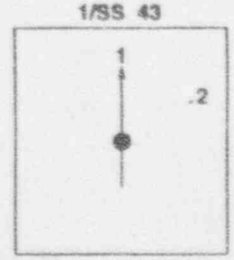
480V BUS 5 BKR 9C SUPPLY TO MCC5



CONTACTS	POSITION	
	1	2
A11 - B11		X
A12 - B12	X	

1/SS 43

1/SS 43

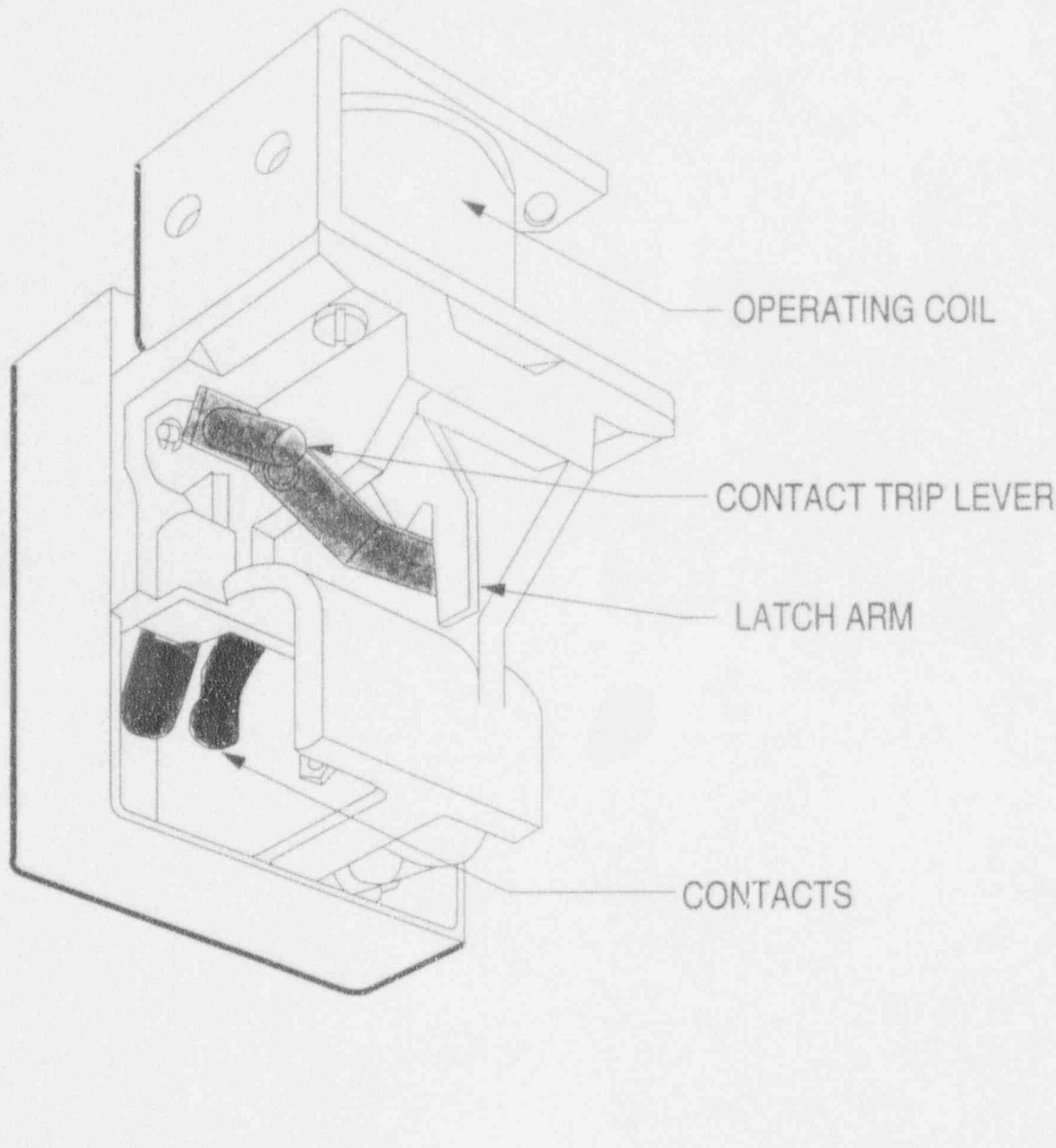


WESTINGHOUSE CO. W2
2 POSITION MAINTAINED

NORMAL CONFIGURATION

- BUS 5 - PREFERRED BUS
- BUS 5 AND BUS 6 ENERGIZED
- BKR 9C CLOSED
- BKR 11C OPEN

52 X RELAY

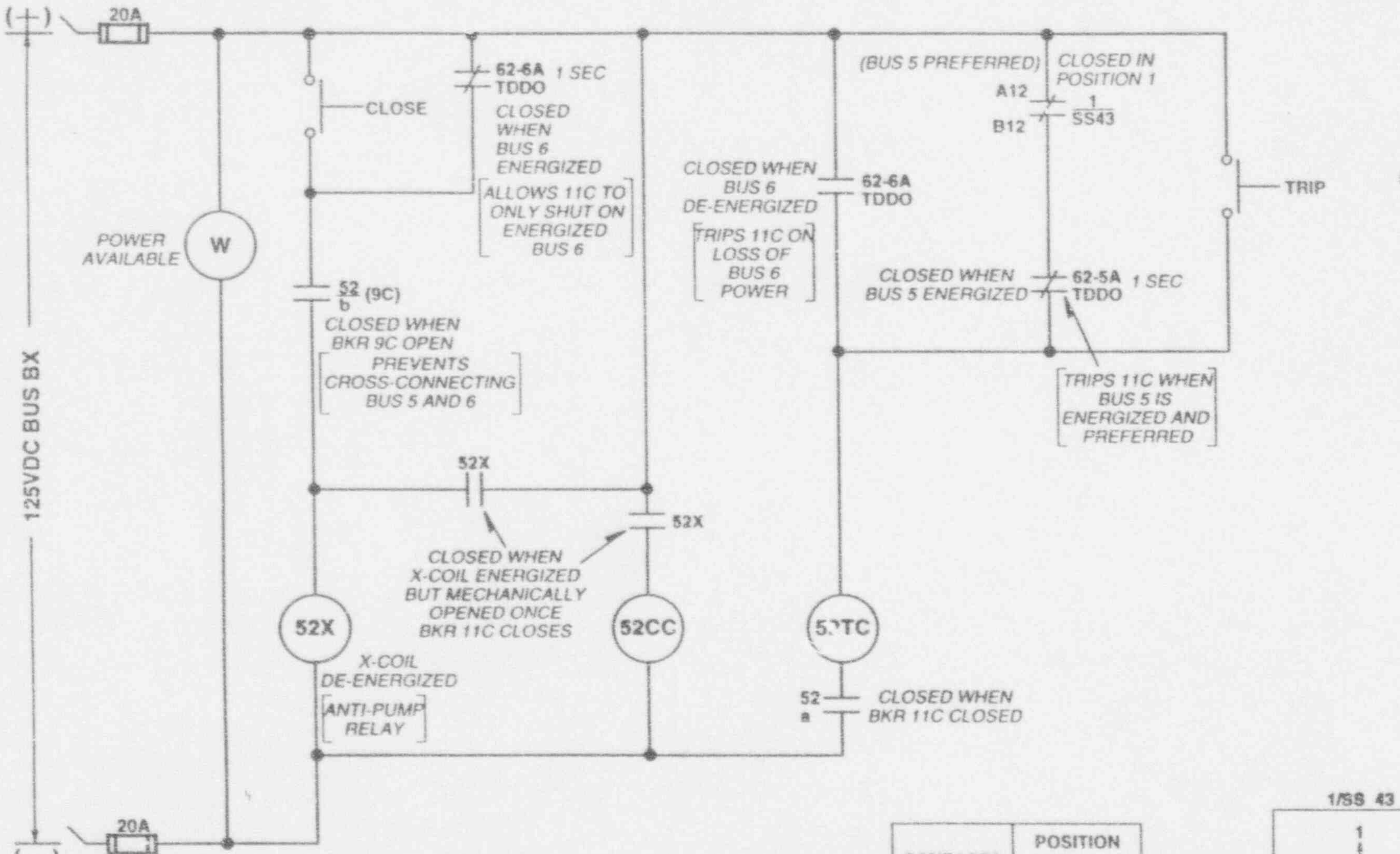


Problem Chronology

- 1993 Refueling Outage Testing (June 27, 1993)
  - First Formal Test of Auto Transfer
  - After Two Successful Closures Breaker 11C Fails to Close
  - Troubleshooting:
    - Visual Inspection of 9C and 11C Breakers
    - Breaker 11C or Control Circuit Determined to be at Fault
    - Agastat 62-6A Operation and Contact Resistance Verified OK
  - Repairs Included:
    - Replacement of Agastat and 52X Relay

ORIGINAL DESIGN

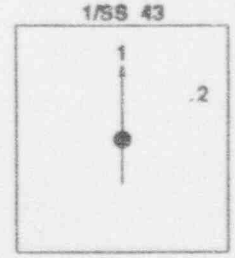
480V BUS 6 BKR 11C SUPPLY TO MCC5



CONTACTS	POSITION	
	1	2
A11 - B11		X
A12 - B12	X	

1/SS 43

1/SS 43



WESTINGHOUSE CO. W2
2 POSITION MAINTAINED

NORMAL CONFIGURATION

- BUS 5 - PREFERRED BUS
- BUS 5 AND BUS 6 ENERGIZED
- BKR 9C CLOSED
- BKR 11C OPEN

Cycle 18 Testing

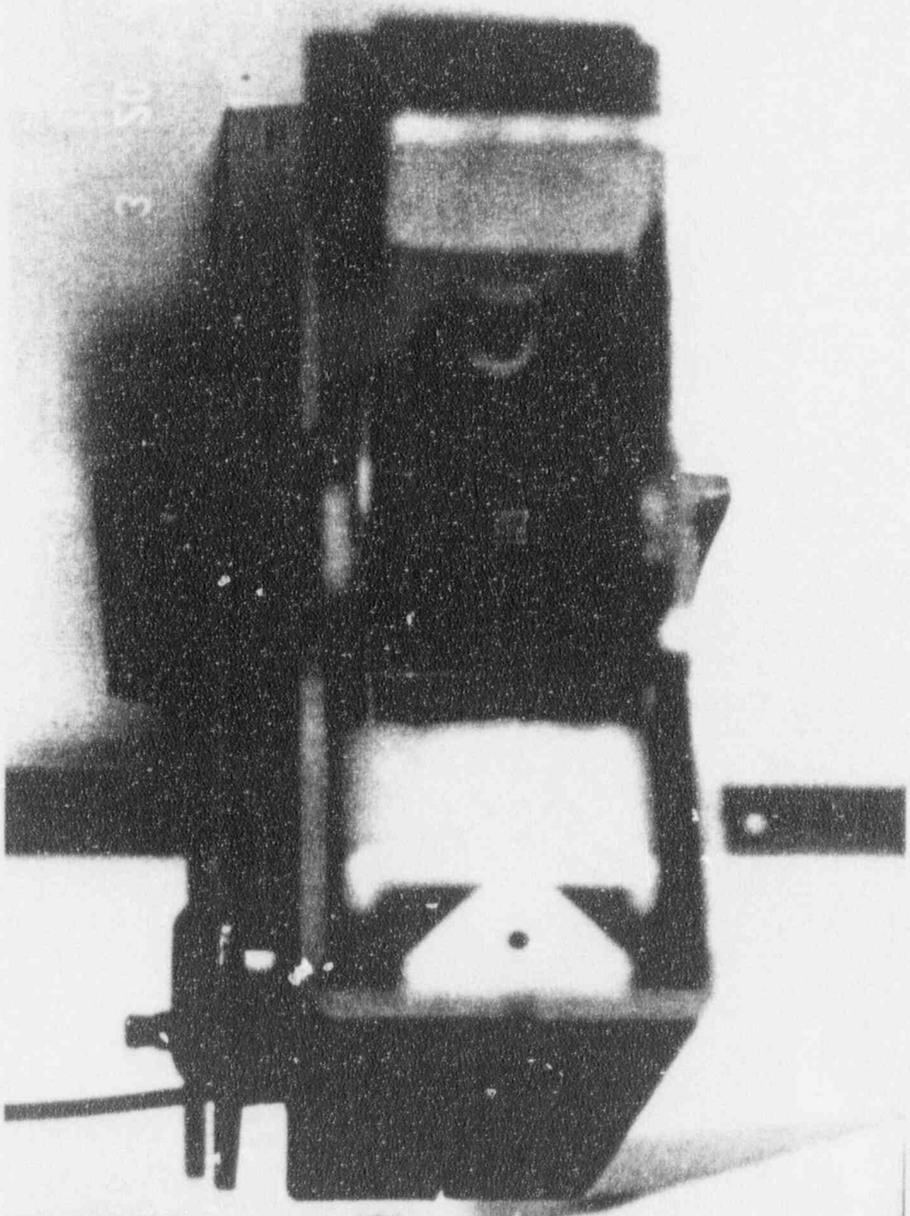
- On-Line Verification of 52X Relay Dropout Was Performed 7 Times
- Bench Test of a DB-25 Breaker and Actual Circuit Components Resulted in No Failures After 1500 Cycles

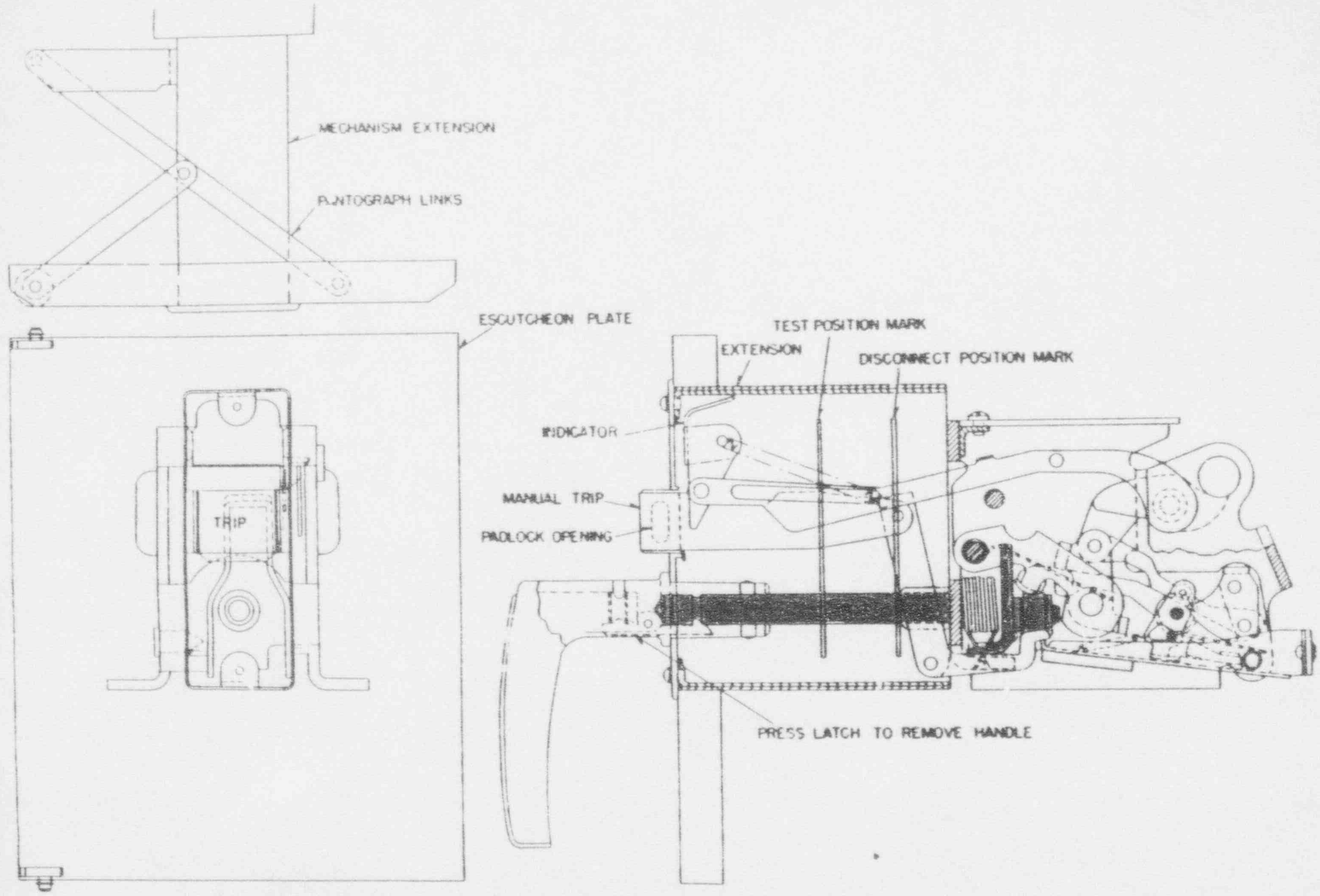
1994 Service Water Outage Testing

- Special Test Developed
- Initial Test 2/16/94 0130 hrs.
  - Breaker 11C Failed to Close After One Successful Closure
- Retest 1: 2/16/94 1940 hrs.
  - Breaker 11C Failed to Close Upon Initial Demand
- Retest 2: 2/16/94 2100 hrs.
  - Fully Successful With Spare Breaker (16C) Installed
- Retest 3: 2/18/94 1200 hrs.
  - Fully Successful With Spare Breaker (16C) Installed

1994 Service Water Outage Testing

- Troubleshooting Breaker 11C:
  - Visual Inspection Revealed Snap Ring Out of Position
  - Breaker 11C Failed to Close on Bench
  - Breaker 11C Successfully Tested on Bench (5 Cycles) With New Operating Mechanism
  - Breaker 11C Inserted Back Into Switchgear and Tested Successfully
- A Similar DB-25 Breaker Failed on Bench With Its Snap Ring Intentionally Mispositioned
- Dimensional Inspection of Snap Ring and Shaft of Breaker 11C in Comparison to Design
- Tensile Test of Snap Ring in Comparison to New Item
- Historical Review Identified Similar Event During 1986 Refueling Outage (1/17/86)




MECHANISM EXTENSION
PANTOGRAPH LINKS
ESCUTCHEON PLATE
TRIP
TEST POSITION MARK
EXTENSION
DISCONNECT POSITION MARK
INDICATOR
MANUAL TRIP
PADLOCK OPENING
PRESS LATCH TO REMOVE HANDLE

Root Cause

- The Cause of the Failures of MCC-5 Supply Breaker 11C is the Operating Shaft Snap Ring Being Out of Position
- The Root Cause has been Determined to be Improper Installation of the Snap Ring Following Breaker Maintenance

Corrective Action

- A New Operating Mechanism Has Been Installed in The 11C Cubicle And Satisfactorily Tested
- Preventive Maintenance Procedures Will be Revised to Provide Detailed Guidance on DB-25 Breaker Maintenance
- Technical Training Will Incorporate This Experience Into The Breaker Training Module
- Inspected Similar Breakers For Snap Ring Position
- Replaced 52X Relays With Westinghouse Improved Design (Controlled Magnetic Air Gap)

ABT
MODIFICATIONS

George Townsend

Re-Design Criteria

- Do Not Have a "Preferred" Source That the Scheme Will Always Seek. The Scheme Should Seek a Stable Power Source, and Once Obtained, Should Remain There.
- Limit the Number of Challenges to Breaker Operations
- Keep the Scheme Relatively Simple. This Includes Design, Installation, and Maintainability.

Equipment Removals

- Manual Selector Switch SS43
- Timing Relay 62-5B
- 'Close' and 'Trip' Electrical Push-Buttons Were Removed From the Control Circuit

Main Features of Re-Design

- 480V Bus 5 Breaker 9C is the Selected Breaker to Normally Supply MCC-5
- Assuming a Total Loss of Offsite Power, Breaker 9C Remains Closed. Once the Emergency Diesel Generators Start:
  - If Bus 5 is Energized Before Bus 6, MCC-5 Remains Supplied From Bus 5 (Breaker 9C Remains Closed).
  - If Bus 6 is Energized Before Bus 5, Breaker 9C Will Trip and 480V Bus 6 Breaker 11C Will Close and Energize MCC-5, and Remain in This Alignment.

Main Features of Re-Design

- Assuming a Loss of Power on Bus 5 Only, Breaker 9C Will Trip and Breaker 11C Will Close
- Assuming a Loss of Power on Bus 6 Only, Breaker 9C Will Remain Closed and Aligned to MCC-5
- Whenever Breaker 11C is Closed (Off-Normal Position) an Alarm is Received in the Control Room

Probabilistic Risk Assessment (PRA) Aspects of The Re-Design

- The Re-Design Increases the Reliability of the ABT Scheme
- MCC-5 Failure Probability Decreases By an Order of Magnitude (From Approximately 5.9×10^{-2} to 5.7×10^{-3}) From the Original Design
- This Results in a Measurable Decrease in the Loss of Off-Site Power Contribution to Core Melt Frequency

Service Water

BACKGROUND

Jere LaPlatney

March 1993

- Flapping for UT Inspection
- GL 90-05 Relief Request Submitted

Summer 1993 Refueling

- Weld Removed Intact
- Generic Look at "Sister" Weld
- Operability Assessment
- First Three Welds Replaced
- Sound Metal Found at Cut 1 Foot From Elbow - Problem Viewed as Highly Localized

Summer 1993 Refueling

- Lab Report
  - Poor Weld Quality With Some MIC
- Problem Treated as Localized Combination of Poor Welds and Potential MIC
  - Sound Base Metal Downstream Gave False Confidence
- Piping Repaired and Returned to Service
- Initiated Engineering Evaluation of Potential MIC Problem

Fall 1993

- Evaluation of Weld Samples Removed From System
- Radiography of Diesel Welds Considered
- Underground Pipe Inaccessible
  - Project to Reroute Pipe Initiated
- Elbow Removal Plan Adopted as Superior to Radiography so Active MIC Samples Could be Taken

January 1994

- Elbow Removed, MIC Samples Taken
- Welds Visually Acceptable, Much Better Condition Than Original Welds
- MIC Samples Inconclusive

January / February 1994

- Operability Evaluation Method Questioned by NRC
- Condition of Other Welds in Service Water Questioned by NRC
- Analytical Method Changed

February 1994

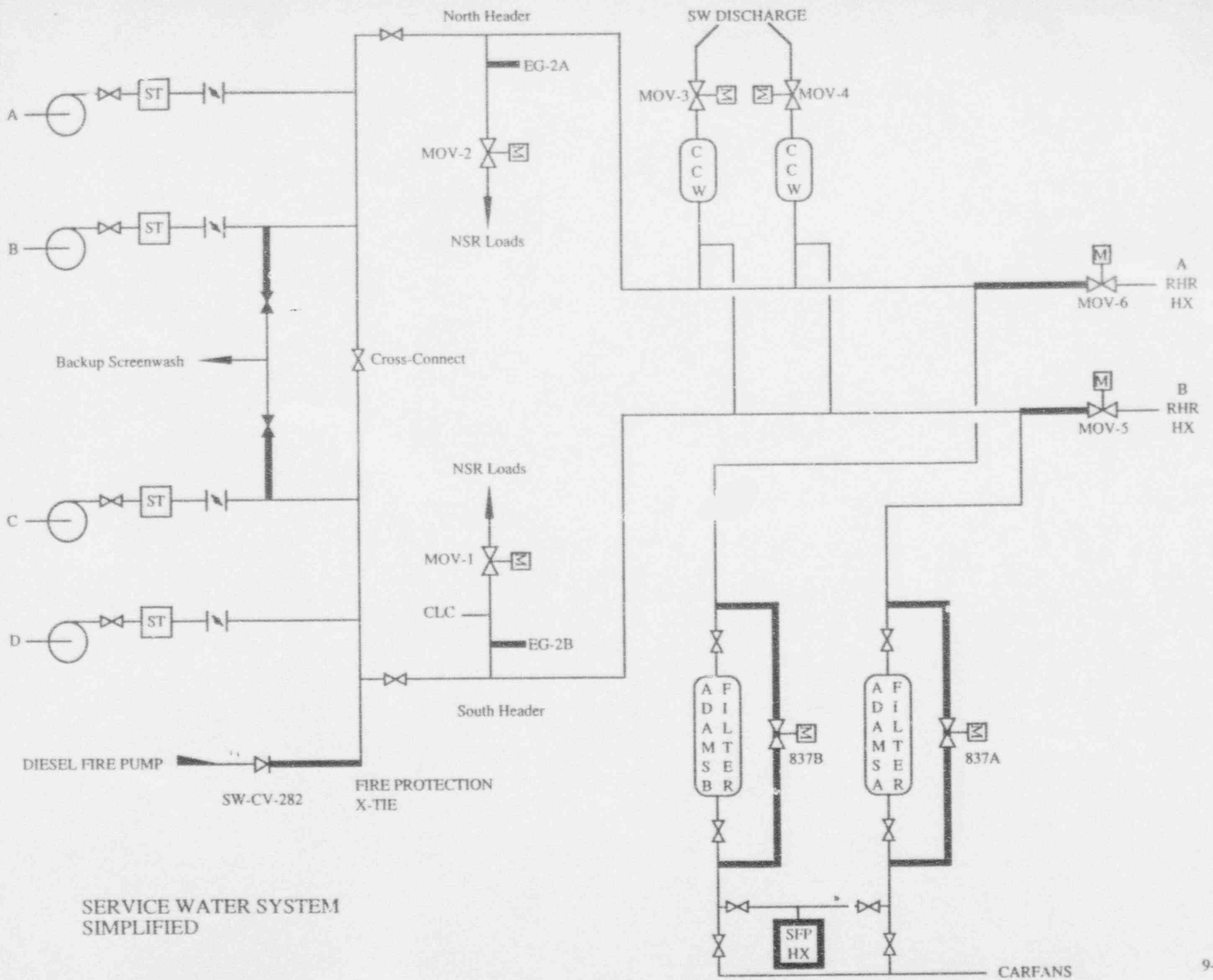
- All Accessible Welds in Diesel SW Radiographed
- Three Welds of Immediate Concern Identified
- Efforts to Characterize Flaw Depth Ultimately Resulted in Leak
- Confidence in ECT Lost
  - Service Water Declared Inoperable Based on Potential for Common Mode Failure

Management Actions

- Took a More Conservative Posture on Potential MIC in Service Water
- Commit to and Implement Significant Pipe Replacement to Adequately Address High Risk MIC Sites
- Initiate Evaluation on Decision Making Process
- Perform SWOPI
  - Includes Review of Response to GL 89-13

SYSTEM OVERVIEW
INSPECTION ACTIVITIES AND RESULTS
PROBLEM BOUNDING
CORRECTIVE ACTION
MONITORING
TECHNICAL SUMMARY

Tom Galloway



SERVICE WATER SYSTEM
SIMPLIFIED

9-21-93

Inspection Activities

- Initial Focus: Safety Related, Stagnant Legs (High Risk)
  - EDGA & EDGB Supplies
  - SWS to RHR Heat Exchangers
  - Adams Filter Bypass Lines
  - Backup Screenwash
  - Fire Protection Cross-Tie
  - Spent Fuel Pool (SFP) HX Supply
- Used RT as Initial Inspection Method
- Retained Samples for Post-Mortem (Underway)
  - Visual, RT / UT Correlation, Analysis
  - Validate Inspection / Monitoring Processes
  - Operability Assessment (June 1 LER Update)

Inspection Results

LINE	# Welds	# RT'd	#PM	Post-Mortem	Comments
EG2A Supply (1972)	12	12	3	2, 7, & 22	Low to Medium corrosion most welds. Welds 7 & 22 areas of Heavy corrosion.
EG2A (Post 1990)	34	0	0	None	RT in progress
EG2B Supply (1972)	10	7	1	21	3 Welds inaccessible (hangers). Low to Medium corrosion on most welds.
EG2B (Post 1990)	37	10	0	None	Welds considered SAT.
North B/U Screenwash	4	4	2	2 & 3	Some areas Low to Medium corrosion.
South B/U Screenwash	2	2	0	None	Welds considered SAT.
SWS to "A" RHR	21	13	6	23,23A,24,25,27A,28	Low to Medium corrosion on most welds. Welds 23/23A have areas of Heavy corrosion.
SWS to "B" RHR	18	6	4	2,5,6,&9	Low to Medium corrosion on most welds. Welds 5,6,9,&10 have some areas of Heavy corrosion.
"A" Adams Bypass	7	7	0	None	Small areas of Low corrosion on two welds (W7 &12)
"B" Adams Bypass	6	6	2	3 & 4	Areas of Low to Medium corrosion on two welds (W3 & 4)
Fire Protection X-Tie	11	11	5	5 thru 8 &11	Areas of Low to Medium corrosion most welds. W11 areas of Medium to Heavy corrosion.
SFP Cooling	10	10	4	4 thru 7	Low to Medium corrosion most welds. Some Medium to Heavy (W4,7,10).
Totals	**172**	**88**	**27**		

Problem Bounding

- Directly Addressed Highest Risk (Primarily Via Replacement)
- Independent Consultant Utilized (Dr. R. Lutey)
- Root Cause Bounding Inspections (Visual, Micro-Biological, Chemical)
- Representative Cross-Section Low / Intermittent Flow Locations:
  - CCW HX
  - "C" SW Pump Discharge
  - Adams Filter Supply
  - Adams Filter Backwash
  - SWS Supply to RHR (Header)
  - CAR Fan Cooler Elbow
- No Evidence of MIC Involvement With Corrosion

Corrective Action

- Replaced EDGA & EDGB Supply Piping
  - Included Re-Routing to Eliminate Inaccessible Lines
- Replaced (or In Process) All Safety Related Stagnant Legs Above, Except:
  - 1990 EDG Lines
  - South B/U Screenwash
- 100% RT on New Piping Welds
  - Precludes MIC Initiation Site
  - Provides Monitoring Baseline
  - Acceptance Criteria for New Welds ANSI B31.1 (1986)
- Replacement Seen as Major Step in Preventing Further Failures

Monitoring

- Graded Approach Based on Relative Risk
- Adjust Program Based on Observations
- Utilize Visual, Sampling, RT (Welds), UT (Piping)
- Factor in Post-Mortem Results for NDE
- Inspections / Samples Incorporated as Routine
- Layup Controls for Intermittent Flow Locations
- Water Treatment (Chlorination, Biocides if Approved)
- Physical Modifications (Spool Pieces, Bug-Pot, Test Spigots)

Technical Summary

- Replacement of High Risk Piping Sections (Safety Related, Stagnant)
- Inspections & Analyses to Define and Bound Problem
- Post-Mortem Analysis
  - Validate Inspection / Monitoring Processes
  - Operability Assessment (June 1 LER Update)
- Near & Longer Term Monitoring / Mitigation Efforts
  - Applies to Whole System
  - Graded Based on Relative Risk
  - Program Adjusted Based on Observations
  - Predictive: Action Prior to Concern

ROOT CAUSE

Paul Mason

Root Cause Conclusion

- Degradation in the Service Water System Resulted From:
  - microbiological influenced corrosion (MIC)
  - in stagnant flow lines
  - at welds with lack of penetration (LOP)

Objective of Root Cause Inspections

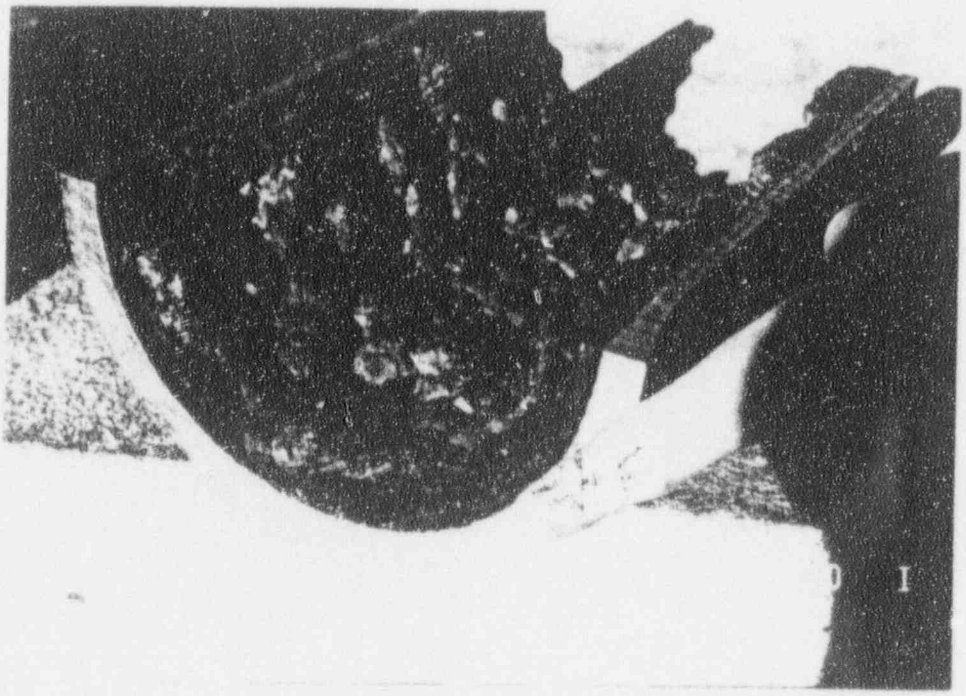
- Define the Corrosion Mechanism
- Determine if the Mechanism(s) Was Associated With Any Flow Conditions (i.e. Continuous, Intermittent or Stagnant)
- Identify Particular Locations in the System

Type of Inspections Performed

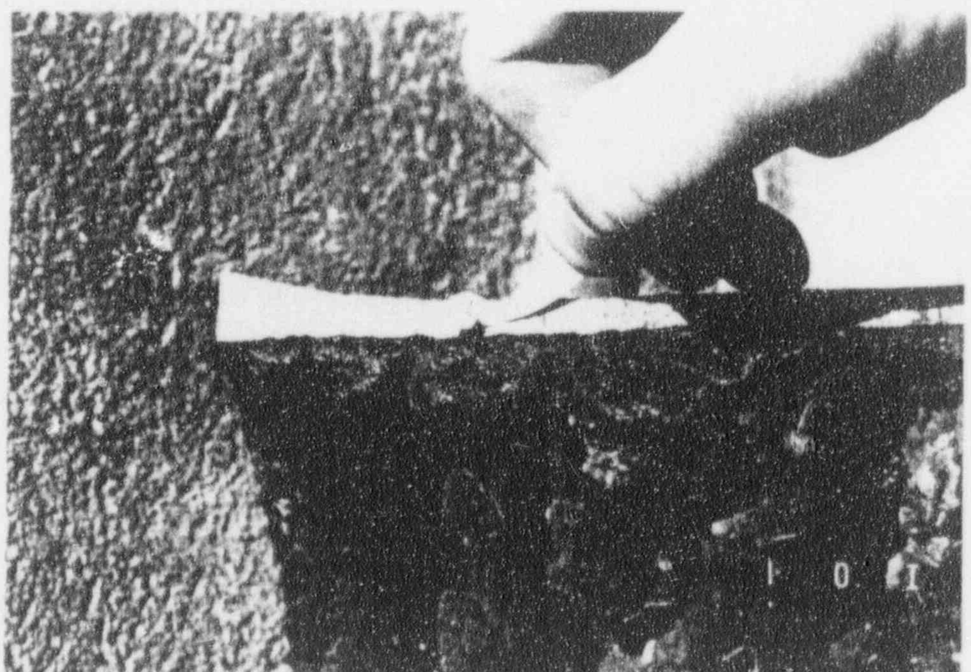
- Visual Examination
- Microbiological Survey
  - Aerobic and Anaerobic
- Chemical Analysis of Water
- NDE (RT and UT)
- Metallurgical Laboratory Post-Mortem

Observations of Stagnant Lines

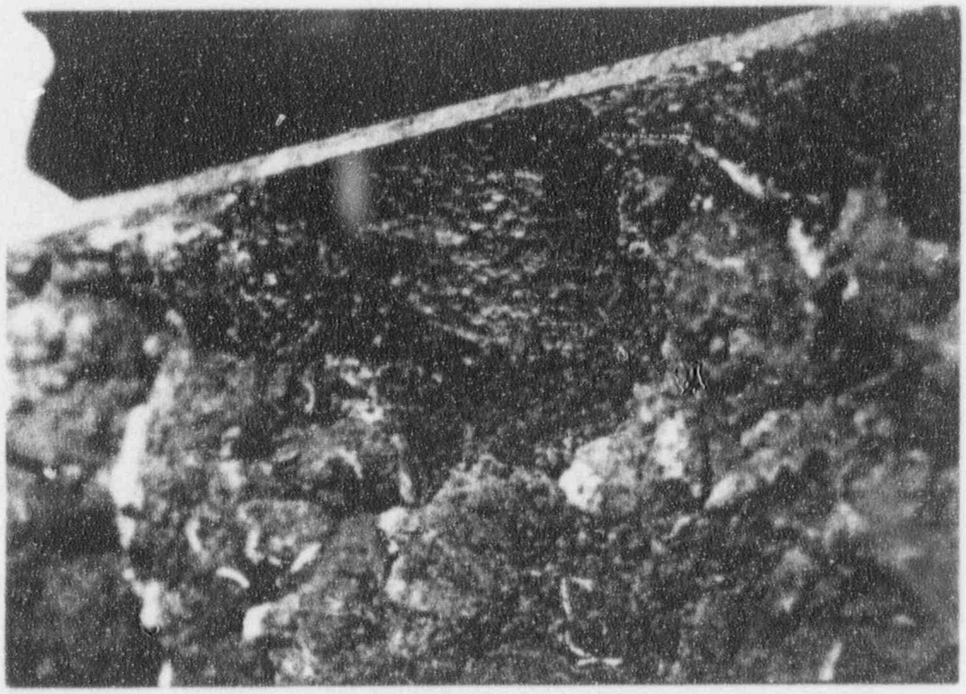
- Visual:
  - Tubercles 1/2" to 2" dia. 1/2" Thick
  - Some Attack of Base Metal Under Tubercles
  - Some Pits in Welds 1/4" Dia., 1/2" into Weld, 50% to 80% Through Wall
- Microbiological:
  - Positive Growth of Aerobic Metal Oxidizing Bacteria
  - Positive Growth of Anaerobic Acid Producing Bacteria
- Chemical Examinations:
  - Water Sample Analysis at MIC Sites Indicated Only Slightly Corrosive or Stable Water Environment



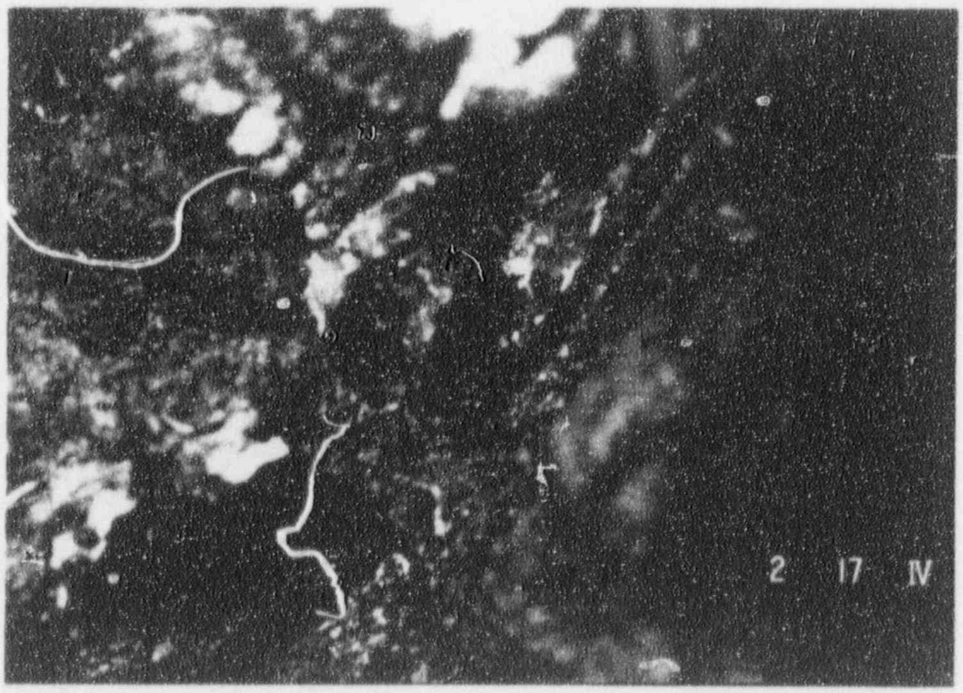
Weld #21 EDG 2/17/94



Weld #21 EDG 2/17/94



Weld #21 EDG 2/17/94



Weld #21 EDG 2/17/94

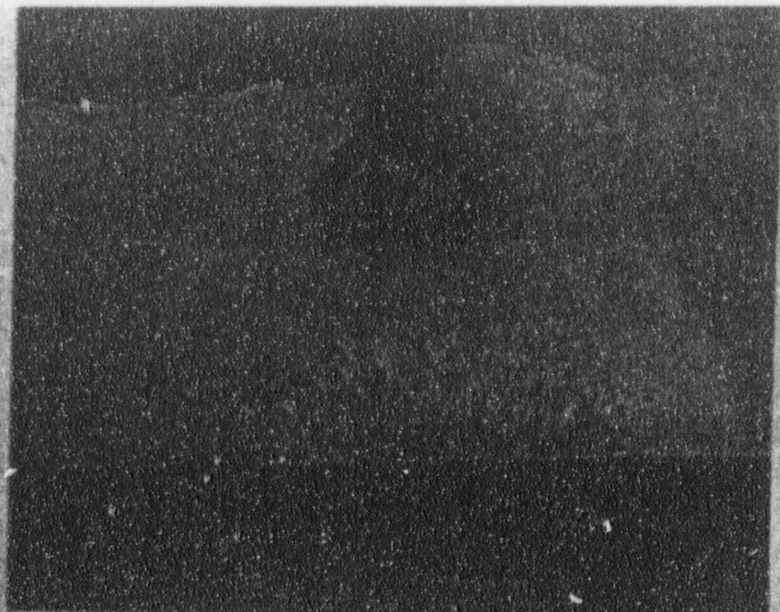


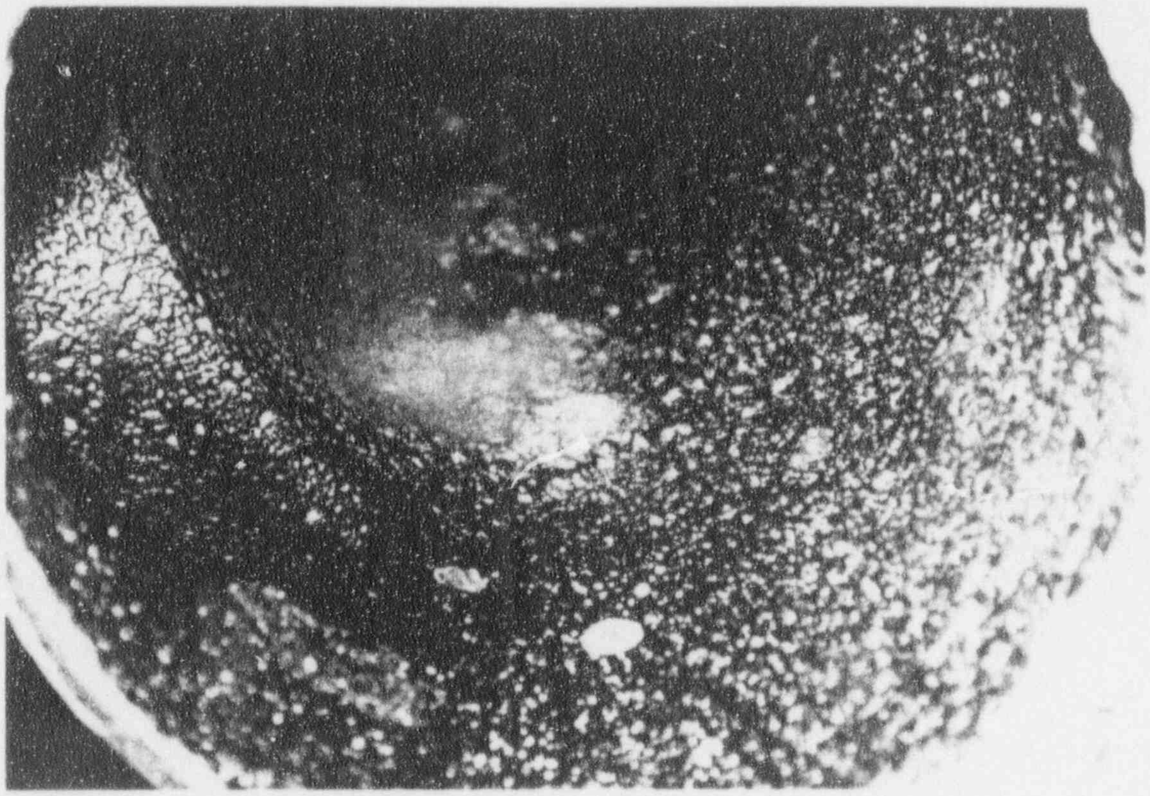
Figure 10 Mag. 6X
Photograph of 1993 CY Service Water Weld
with pit

Supply to RHR Heat Exchanger


"B" RHR
Weld 2

Observations of Process & Intermittent Lines

- Visual:
  - Minimum General Corrosion on Base Metal
  - Randomly Scattered Tuberculation < 10% of Wall, < 1/2" Dia.
  - No Significant Corrosion Attack
  - No Visual Evidence of Microbiological Involvement Seen
- Microbiological:
  - Passive Anaerobic Bacteria Found in Aerobic Environment



Service Water Supply
Header to Adams Filters and RHR Heat Exchangers

Service Water Pump "C" Discharge Elbow

Conclusions

- Root Cause of Localized Weld Degradation
  - Microbiological Influenced Corrosion (MIC)
  - in stagnant flow conditions
  - located at welds with lack of penetration (LOP)
  - Basis
    - Microbiological, Visual & Chemical Test
    - Very Active Population of Anaerobic Bacteria at Degraded Sites
    - Environment Conducive to MIC Mechanism (LOP & Stagnant Flow)
    - Confirming Chemical Analysis of MIC Corrosion By-Products
- Results of Examinations of Process Flow and Intermittent Flow Sites
  - No Evidence of Microbiological Involvement with Corrosion
  - No Evidence of Significant Pitting

Mitigation (Corrective Actions)

- Physical Elimination of Stagnant Sites
  - Replace With New Pipe and Higher Quality Welds
  - Eliminates Potential MIC Sites - Reduces Potential for MIC
- Continuous Chlorination to be Maintained

OPERABILITY & DISPOSITION CRITERIA

Nelson Azevedo

Operability of Diesel Supply Welds No. 21, 22 and 12

- Bounding Flaw Assumed to be 65% Through Wall 360° Around the Circumference
- Bounding Loads Obtained From the Dynamic Seismic Evaluation Per SEP Requirements
- Flaw Assumed to be Crack-Like and Evaluated in Accordance with ASME Section XI Requirements
- Bounding Flaw was Found to Meet the ASME Section XI Structural Margins of Safety
- All Old Welds Evaluated to Date Have Demonstrated Operability (i.e. Compliance With the ASME, Section XI Code). Some Evauations Still On-Going.

Structural Evaluation of Old Welds During Shutdown

- Old Welds Found to Contain Defects in Excess of Those Allowed by ANSI B31.1 Were Identified and Non Conformance Reports (NCRs) Initiated
- The Indications Identified in the Above NCRs Were Then Evaluated in Accordance With the ASME Section XI IWB-3500 and IWB-3600
- All Welds Found to Exceed the Structural Requirements of ASME Section XI Were Repaired
- All Welds With MIC-Like Indications Were Repaired

Evaluation of New Replacement Welds

- All New Welds Were Visually Inspected as Required by ANSI B31.1 for Code Compliance
- Supplementary RT Inspection Was Also Performed on all New Welds
  - Purpose of RT Was to Provide Baseline for Future Inspections, and
  - Ensure That the Welds Were Defect-Free at the Inside Surface
- Indications Which Exceed the ANSI B31.1 RT Standards Will be Repaired

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CLOSING REMARKS

Jere LaPlatney

Closing Remarks

- Rigorous Inspection Program
- Significant Corrective Action
- Strong Follow-up Actions
  - Review Decision Making
  - SWOPI