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Region I

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License Nos. DPR-53
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Licensee: Baltimore Gas and Electric Company

Post Office Box 1475

Baltimore, Maryland 21203

Facility Name: Calvert Cliffs Nuclear Power Plant, Units 1 & 2

Inspection At: Lusby, Maryland

Inspection Conducted: November 5 - December 18, 1984

Inspectors: K P Fevlie (FOR) 1/29/85
T. Foley, Senior Resident Inspector date

K P Fevlie (FOR) 1/29/85
D. C. Trimble, Resident Inspector date

Approved By: T. C. Elsasser 2/1/85
T. C. Elsasser, Chief, Reactor Projects Section 3C date

Inspection Summary:
Inspection on November 5 - December 18, 1984 (Report No. 50-317/84-31 and 50-318/84-31)

Areas Inspected: Routine resident inspection (169 hours) of the control room, accessible parts of plant structures, plant operations, radiation protection, physical security, fire protection, plant operating records, maintenance, surveillance, open items, IE Bulletin, independent inspection and reports to the NRC.

Results: Several significant plant problems occurred during the inspection. The licensee took corrective action in each case. Significant commitments were made which should improve the reliability of reactor trip breakers (two instances of slow breaker response times occurred during the period) (Section 6). Corrective

action programs are in progress or planned by the licensee to complete repairs on the Unit 1 Salt Water System (one hole was identified in piping for each subsystem) and to assess the integrity of concrete lined piping (Section 4.c); correct operability problems on both Main Steam Isolation Valves (Section 6); correct High Pressure Safety Injection Valve flow settings (Section 6); assess and correct wall thinning problems on extraction steam lines and assess integrity of main steam piping (Section 6); correct any deficiencies in refueling procedures with respect to cavity seal or nozzle dam failures (Section 11); and evaluate of Unit 1 Containment tendon problems (Section 13). Appropriate management attention and corrective action appears evident in each case with the exception of the No. 12 MSIV in which the specific root cause of failure was not identified prior to declaring the valve operable nor identified within a timely manner thereafter.

DETAILS

1. Persons Contacted

   Within this report period, interviews and discussions were conducted with various licensee personnel including reactor operators, maintenance and surveillance technicians, and the licensee's management staff.

2. Summary of Facility Activities

   Details of the following are included in the body of this report.

   At the beginning of the period both units were at 100% power. The licensee had determined that commercial grade HEPA filters were purchased and installed in safety related applications.

   On November 11, 1984 testing of Unit 1 Containment tendons identified three adjacent tendons with lift off forces below their expected values. The licensee is currently performing an engineering analysis for possible effects.

   On November 21, Unit 1 was manually tripped due to high differential pressure on the traveling screens caused by an influx of fish. Immediately following the trip an extraction steam line ruptured filling the Turbine Building with steam and causing first degree burns to one individual. Repairs were made and the unit returned to operation on November 26, 1984.

   During startup, while testing the Reactor Trip Breakers (RTB's), the licensee identified two breakers whose trip times were excessive. Adjustments were made and the startup continued.

   Repeatedly during the period, high differential pressures were experienced across the traveling screens due to fish impingements causing circulating water pumps to be secured, power reductions and minor degradation of the traveling screens.

   On November 27, four NRC personnel commenced an onsite review of the Control Room for Human Factors aspects.

   On November 29, Unit 1 reduced power to investigate increasing trends on both RCS leakage calculation and Containment Particulate Activity. The unit was subsequently shut down to hot standby (Reactor Critical). Repairs were made to a flex hose on the Reactor Coolant Pump #11B pressure sensing line and a pressurizer sample valve. The unit returned to power operations on December 2.

   On December 7, licensee management discussed the 1984 Systematic Assessment of Licensee Performance with Region I management at the Region I office.

On December 10, the licensee notified the resident inspector that two holes had developed on the Unit 1 Salt Water System. One hole required a temporary patch and the other was isolated and removed from service.

On December 12, the licensee received an analysis which had previously been requested from the vendor for the Main Steam Isolation Valves (MSIVs) which indicated that the No. 11 MSIV may be inoperable due to hydraulic fluid leakage. The licensee shutdown Unit 1 that afternoon, and declared an Unusual Event because of a shutdown required by Technical Specifications. While in progress of shutting down, No. 12 MSIV failed to shut completely and was also declared inoperable. During this shutdown period repairs were made to the MSIVs and part of the salt water system, seals for two Reactor Coolant Pumps were replaced and extensive nondestructive testing of steam and feed lines and associated repairs was conducted.

The licensee also identified during this time that the High Pressure Safety Injection throttle valves have repeatedly been required to be adjusted to ensure correct flows required by the Technical Specifications and the accident analysis and that "as found" data has continually shown the flow outside the bounds of the analysis.

Although several significant issues occurred during this period, the licensee acted appropriately for each (with the exception of not identifying the specific failure mechanism of the #12 MSIV (Section 6)). The licensee has traditionally been aggressive in uncovering flaws in design analysis, performing reanalysis and taking appropriate corrective action. Salt water system corrosion has been tracked and evaluated by licensee engineering groups. A Region I inspector reviewed the specific salt water system corrosion problems and licensee's action on December 17-18, 1984 and concluded appropriate action was being taken.

3. <u>Licensee Action on Previous Inspection Findings</u>

(Closed) Unresolved Item (317/82-12-04): Penetration in East Wall of Intake Structure Not Sealed to Ensure Watertight Integrity. The licensee identified all unsealed wall penetrations. Those penetrations were then sealed under Facility Change Request FCR 82-1048. Work was completed on March 15, 1984. A construction specification change will be made to flag the need for sealing any future penetrations bored in the wall.

(Closed) Violations (317/84-03-03 and 317/84-11-02): Improper Tagout of the Oxygen Analyzer Cabinet Due to Inadequate Valve Labeling and Failure of Tagging Personnel to Properly Identify the Valves to be Tagged. Improper Lifting of a Valve Power Lead in a Hydrogen Analyzing Cabinet Due to Inadequate Valve Labeling. As stated in Section 3d of Inspection Report 317/84-11, 318/84-11 general labeling of plant valves is good. The weakness pointed out by these violations was a specific case of poor labeling of Oxygen and Hydrogen analyzer cabinets. The licensee corrected the valve labeling discrepancies. Additionally, the tagging program was strengthened by instituting a qualification program for personnel designated to perform mechanical safety tagging and by instructing taggers to carry more information into the field (including a copy of the tagout record which contains a complete functional description of each valve to be tagged). That qualification program is described in and implemented by Calvert Cliffs Instruction CCI 112E, Change 1, dated April 5, 1984.

4. Review of Plant Operations

a. Daily Inspection

During routine facility tours, the following were checked: manning, access control, adherence to procedures and LCO's, instrumentation, recorder traces, protective systems, control rod positions, Containment temperature and pressure, control room annunciators, radiation monitors, radiation monitoring, emergency power source operability, control room logs, shift supervisor logs, tagout logs, and operating orders.

No inadequacies were identified.

b. System Alignment Inspection

Operating confirmation was made of selected piping system trains. Accessible valve positions and status were examined. Power supply and breaker alignment was checked. Visual inspections of major components were performed. Operability of instruments essential to system performance was assessed. The following systems were checked:

-- Unit 2 Emergency Core Cooling System in RWT Room checked on November 29, 1984.

-- Unit 1 Auxiliary Feed Water System checked on November 16, 1984.

-- Unit 1 Containment Spray System checked on December 18, 1984.

During an inspection of the Emergency Core Cooling System (ECCS) components on November 29, 1984, the inspector noted several housekeeping problems in the Unit 2 Refueling Water Tank (RWT) room. Historically, the RWT rooms have not been as well maintained as other plant areas. Unlike most contamination control areas these rooms are accessed directly from outside the Auxiliary Building. Because of their remote locations, the radiological controls group does not monitor personnel access into and out of these rooms as closely as typical contamination control areas. For these reasons, the likelihood of the spread of contamination to outside areas is increased. Therefore, good housekeeping in the RWT rooms is especially important. The inspector noted lab coats draped over warning barrier ropes, yellow booties and a lab coat on the floor of an uncontaminated portion of the room, a dirty step-off pad, and a large amount of boron residue on the floor. The principal borated water leakage path appeared to be from the casing of the RWT recirculation pump. The casing drain line to the sump was stopped up. A Maintenance Request

(MR) had been initiated on that problem. The room's sump pump was out of service. Again an MR had been initiated. Additionally, housekeeping in the Control Room Heating, Ventilation and Air Conditioning (HVAC) room on the 69 foot level and on the 45 foot level Rad Waste areas has not been routinely maintained, and has periodically deteriorated below standards set for the rest of the facility. Principal contributors to this have been the construction activity on the 69 foot level. The facility's newly constructed Rad Waste facility is nearing completion and should alleviate much of the current rad waste over crowded storage areas. The inspector reported these conditions to the Plant Superintendent who initiated action to reestablish housekeeping controls in these areas.

No violations were identified.

c. Biweekly and Other Inspections

During plant tours, the inspector observed shift turnovers; boric acid tank samples and tank levels were compared to the Technical Specifications; and the use of radiation work permits and Health Physics procedures were reviewed. Area radiation and air monitor use and operational status was reviewed. Plant housekeeping and cleanliness were evaluated. Verification of the following tagout indicated the action was properly conducted.

-- Tagout 7661, Diesel Generator #12 checked on November 27, 1984.

No violations were identified.

d. Other Checks

During the course of the following events the inspectors attended several POSRC meetings and the outage meetings regarding the event in order to monitor the licensee's activities. The inspector also made independent observations and verifications of licensee's actions during plant tours.

On November 11, 1984 the licensee notified the inspectors that they had determined that 250 commercial grade High Efficient Particulate Air (HEPA) filters were received as nuclear grade safety related filters and that several of these had been installed. The filters were being utilized in safety related applications in the ECCS pump room coolers and Spent Fuel Pool filter trains. The licensee immediately began exchanging the commercial grade filters in use in safety related applications with known nuclear grade filters being used elsewhere in the plant, then tested the filter trains.

Subsequently, the licensee performed a safety evaluation of the acceptability of the non-nuclear grade HEPA filters in nuclear grade applications and concluded these commercial grade filters are suitable for use in nuclear applications; that the physical differences were not significant with respect to their application. The Plant Operations and Safety Review Committee (POSRC Meeting 84-131) reviewed the safety evaluation and concurred in its conclusion, and further concluded that the remaining filters in the warehouse could also be utilized in safety related applications.

The inspector examined the commercial grade and nuclear grade filters, witnessed replacement of filters in the Spent Fuel Pool and ECCS pump room cooler units, attended the POSRC (meeting 84-131), reviewed the applicable certifications and apparent mislabeling of the filters, and transmitted this information to NRC Region I personnel.

The licensee submitted a report to the NRC Region I dated November 20, 1984 describing the circumstances and concluding that no substantial safety event was created and the series of events may have constituted a "Deviation" as set forth in 10CFR21.3(e). The inspector found no inadequacies in the licensee's actions with regard to this matter.

On December 10, the licensee informed the inspector that two leaks had developed in the Salt Water System (SW). Both leaks are in concrete lined piping immediately down stream of the No. 11 and 12 SW pumps. Temporarily, the licensee patched one leak and isolated the pipe section containing the other leak. Technical Specification (TS) 3.7.5.1 requires at least two independent SW loops to be operable. Both SW trains are currently operable, however, one of the three SW pumps remains out of service because of the recently developed hole.

Preliminary ultrasonic testing indicated that the corrosion/erosion of the leaking pipe sections is localized. Current plans are to replace the leaking sections of pipe and examine adjacent sections. If the excessive deterioration is not localized to the elbow section, then nondestructive examination (NDE) of accessible concrete lined SW piping sections will be performed to assess the extent of the problem. Also, a complete walkdown of the SW piping is scheduled for the Spring 1985 refueling outage.

The inspector observed the fabrication of the new piping sections, as well as the NDE and hydrostatic testing. The inspector has closely followed the progression of the pipe replacement activities.

The licensee has had previous corrosion problems with the SW systems. In May of 1984, Unit 1 was shutdown when extensive deterioration was discovered in the SW channel heads of the Component Cooling Heat Exchangers. At that time, the problem was identified as being graphitic corrosion which was enhanced by galvanic action in the localized areas. Additionally, other SW components were identified as being degraded but, concrete lined pipe sections were not identified as having a significant deterioration problem. For this reason, the licensee is not correlating the present corrosion/erosion problem with the previous graphite corrosion problems. At this writing, replacement of piping for both leaks is in progress. The old piping removed from the #12 header was examined by the inspector. Approximately 0.5 square feet of concrete was missing from the area surrounding the hole. The hole was approximately one inch in diameter. The condition of the concrete lining the pipe was good except for the 0.5 square foot piece which apparently broke free resulting in the hole, and the outer radius of the elbow section which was severely erroded away exposing base metal. It was not apparent, however, that the base metal had been significantly affected. New piping and a new valve are being inserted and the old piping is being sent for metallurgical studies.

No violations were identified.

5. Independent Inspection

During this period the inspector independently sampled five separate water sources from various locations throughout the facility. These samples were obtained in numbered bottles and the origin of each sample was known only by the inspector. An additional two samples were collected, redundant to two of the previous five sample locations. The five samples were counted for gross gamma activity by the licensee. All samples did show natural background radiation activity, and specific spectrograph peaks for Iodine, Cesium and Cobalt were less than the minimum detectable activity (MDA) of:

I-131 < MDA of 8.82E-7 uci/ml

CS-137 < MDA of 2.96E-6 uci/ml

CO-58 < MDA of 1.18E-6 uci/ml.

The two redundant samples taken were counted for activity by NRC Region I personnel. Results compared favorably to those of the licensee as follows:

CO-60 < 5.0E-6 uci/ml and CS-137 < 5.0E-6 uci/ml.

The five sample points included:

(1) Plant bottled water drinking supply.

(2) Plant domestic/portable water "drinking fountain" system.

(3) Licensee recreation facility pond at "Camp Canoy" on site.

(4) On site marsh/wet land west of the new meteorological tower.

(5) Drainage/runoff from the onsite "landfill" where surveyed and controlled material is periodically buried in an effort to reduce radiological waste.

The inspector found no inadequacies during the independent inspection.

6. Events Requiring Prompt Notification

The circumstances surrounding the following events requiring prompt NRC notification pursuant to 10 CFR 50.72 were reviewed. For those events resulting in a plant trip, the inspectors reviewed plant parameters, chart recorders, logs, computer printouts and discussed the event with cognizant licensee personnel to ascertain that the cause of the event had been thoroughly investigated; identified, reviewed, corrected and reported as required.

-- At 5:16 p.m. on November 20, 1984, Unit 1 was manually tripped from 100% power due to the accumulation of fish on the circulating water intake screen. (The large influx of fish is believed to have resulted from a relatively rapid drop in Chesapeake Bay water temperature.) At 5:18 p.m. a steam break occurred and the main steam isolation valves were closed. Investigation revealed a break in the extraction steam line supply to #15A feedwater heater. A worker approximately 50 feet away from the location of the break suffered first degree burns of the face and left hand. He was taken to the hospital and was subsequently released. During the plant trip all plant systems functioned properly.

Analysis of the break revealed a 30 inch long rupture at an elbow in the extraction steam line. The original 0.375 inch steel wall was severely eroded. The licensee performed nondestructive examination on similar elbows in the higher pressure extraction steam lines to determine wall thicknesses.

Extraction steam line repairs were completed on November 25, 1984, and the unit was returned to power operation. A total of five elbows on the #15 and #16 A and B extraction lines were replaced, and an additional ten had patch overlays to strengthen thinned areas.

The licensee has experienced previous failures of extraction steam/feedwater heater piping on both units (at least three failures). A large scale program consisting of NDE testing and replacement of the more severely eroded piping was begun on Unit 2 during the Spring 1984 refueling outage. Some piping was also replaced in 1984 on Unit 1 during a short outage. That program was scheduled to continue on Unit 1 during its next refueling outage (Spring 1985). Originally installed piping is carbon steel A106, Grade B, Schedule 40. Replacement piping has been/will be A234 (1.25% chromium, 0.5% molybdenum).

The licensee estimates that they are only about 15% into the overall program. Main steam piping is also scheduled to be checked (including inside Containment). Some main steam piping locations in the Turbine Building were checked on Unit 2 (Spring 1984), and no significant problems were identified.

The NRC will follow licensee progress in completing their corrective action program (IFI 317/84-31-01).

-- During the week of November 25, 1984, the licensee noted increasing trends on Unit 1 Reactor Coolant System (RCS) leakage. The licensee reduced power on November 28, to investigate the cause of leakage. A Containment entry was made. The leakage sources were identified to be a flex hose on a #11B RCP seal sensing line and a packing gland on an unisolable pressurizer liquid sample line valve. The licensee returned to power operations and made plans for a controlled shutdown on November 30, and plans to effectuate the necessary repairs. The plant was shutdown to Hot Standby and both leaks repaired. The flex line was replaced with stainless steel tubing of the original design before the flex line modification. Packing material was injected into the pressurizer sample valve packing gland which successfully stopped the leak.

Discussions with licensee representatives indicate that tentatively the licensee plans to replace all RCP sensing lines during the next refueling outage and again during every other refueling outage as part of the preventative maintenance program. The unit returned to power on December 3, 1984.

-- During previous months of power operations the licensee identified an increasing hydraulic fluid leak from the lower end seal on the piston actuator of the No. 11 Main Steam Isolation Valve (MSIV). This hydraulic fluid is necessary for control of the valve closure rate. The licensee speculated that an accelerated valve closure rate could result in valve seat damage. Subsequently, the licensee requested a vendor analysis and recommendations. The vendor analysis determined that with sufficient hydraulic fluid lost from the bottom of the actuator, the valve would close too quickly and damage the valve seat. If this were to occur, the valve might not perform its intended safety function.

On December 12 at 3:00 p.m., after receiving and reviewing the vendor's results at the POSRC meeting, the licensee declared No. 11 MSIV inoperable. TS 3.7.1.5 requires that with one MSIV inoperable, the valve must be closed within four hours or the unit be in hot shutdown within twelve hours. In accordance with 10CFR50.72 and the Emergency Response Plan, the licensee declared an Unusual Event at 3:00 p.m. All appropriate notifications were made. The licensee determined that the plant should go to a cold shutdown condition to repair the MSIV and to perform other minor maintenance. Shutdown procedures were initiated at 3:00 p.m. and Unit 1 was removed from the grid at 4:40 p.m. The No. 11 MSIV was successfully (slow stroked) closed at 6:45 p.m.

The licensee continued with the shutdown procedure, but at 9:00 p.m. the No. 12 MSIV was also declared inoperable when it failed to close completely (80% shut) when automatically initiated from the remote station. It appeared that a build up of hydraulic fluid was preventing the valve from fully closing. The licensee bled the hydraulic fluid from the bottom of the actuator through the rod end pressure sensing line and the valve was successfully fully shut at 11:35 p.m.

In order to proceed with the cool down on December 13, the No. 12 MSIV was reopened. The unit achieved hot shutdown and secured from the Unusual Event conditions at 8:15 a.m. Cold shutdown was achieved at 3:00 p.m.

The affected valves were manufactured by Rockwell International. The actuator was manufactured by Greer Hydraulics. Greer has since discontinued the manufacturing and servicing of these actuators. Since then, Paul Munroe Hydraulics has accepted the servicing of these hydraulic actuators.

The licensee disassembled the No. 11 MSIV to replace the bottom actuator seal and discovered that the poly pack seal around the piston was severely damaged. The licensee replaced all of the seals on the No. 11 MSIV actuator. Hydraulic fluid samples were also taken to ensure its quality. The valve actuator was reassembled and the valve tested and declared operable.

The licensee speculated that the cause of the No. 12 MSIV failure was clogged restrictor valves on the actuator. The restrictor valves were replaced. Inspections and flushes of hydraulic ports, lines and components were performed. As a precautionary measure, No. 11 MSIV restrictor valves were overhauled and no problems were noted. Upon disassembly of the No. 12 MSIV restrictor valves which were removed, the licensee found no deficiencies. The No. 12 MSIV was reassembled and tested successfully six times in the cold condition. With the plant at Hot Shutdown, the valve was tested again and failed the second test. The plant cooled down and additional troubleshooting and testing took place.

The licensee then replaced two solenoid operated hydraulic valves and two check valves which could, if operating improperly, provide a leakage path for high pressure hydraulic fluid and lower the operating pressure for the valve actuator piston. The restrictor valves are held open by valve operating fluid pressure. Too low an operating pressure can cause the restrictor valves to shut thereby preventing release of fluid from the underside of the MSIV actuating piston. This results in a hydraulic lock situation. Following the replacement of the above valves, No. 12 MSIV was successfully operated eleven times during cold plant conditions and twice during hot plant conditions.
On the evening of December 25, 1984, the inspector (via telephone) discussed with the General Supervisor Operation (GSO) the adequacy of testing the MSIV with respect to the limited number of hot cycles versus the number of hot failures. The licensee stated that there was no correlation between the

apparent failure mechanism and any thermal parameter; however, they agreed that additional hot testing would provide added assurance of operability. They agreed to perform additional hot strokes of the MSIV if plant conditions permitted. The valve was declared operable and power operations resumed on December 26, 1984. Additional hot testing was not performed since appropriate plant conditions were not established prior to the end of this report period.

During subsequent discussions with the Plant Superintendent, the inspectors expressed concern that the specific root cause of the MSIV failure had not been identified, and that testing of the valve had not provided a high degree of confidence in the valve's long term operability.

The licensee shared the inspectors concern and stated that additional testing of removed suspected failed parts would be performed to confirm the failure mechanism. Additionally, if the failure mechanism was not specifically identified via testing, then more frequent testing of the MSIV would be performed as plant conditions permited. After additional research of the vendors technical manual and system paramters obtained during testing, the inspectors noted that system operating parameters did not meet the design paramters for Hydraulic fluid pressures described in the Greer Hydraulics Technical Manual. The licensee could not explain the differences to the inspectors; however, they stated that they would perform an engineering evaluation of the adequacy of the Hydraulic system.

Regardless of the fact that the valve appeared to meet the operability requirements of Technical Specifications and the Safety Analysis Report, the inspectors expressed their continued reservations about the valve's operability. The inspectors will closely follow the licensee's actions regarding this matter (IFI 317/84-31-04).

No violations were identified.

7. <u>Observations of Physical Security</u>

Checks were made to determine whether security conditions met regulatory requirements, the physical security plan, and approved procedures. Those checks included security staffing, protected and vital area barriers, vehicle searches, and personnel identification, access control, badging, and compensatory measures when required.

No violations were identified.

8. <u>Review of Licensee Event Reports (LER's)</u>

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

LER No.	Event Date	Report Date	Subject
Unit 1			
84-14	10/24/84	11/21/84	Battery Inoperable
84-15	11/20/84	12/10/84	Loss of Circulating Water Caused by Fish Impingement

LER No.	Event Date	Report Date	Subject
Unit 2			
84-08	10/03/84	11/02/84	Reactor Trip on Low Steam Generator Water Level Condition Resulting from the Trip of #22 Steam Generator Feed Pump

b. For the LER's selected for onsite review, the inspector verified that appropriate corrective action was taken or responsibility assigned and that continued operation of the facility was conducted in accordance with Technical Specifications and did not constitute an unreviewed safety question as defined in 10 CFR 50.59. Report accuracy, compliance with current reporting requirements, and applicability to other site systems and components were also reviewed.

   -- LER 84-14 and 84-15 were included for onsite review.

   No violations were identified.

9. Plant Maintenance

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

-- P84-7149, Add oil to Dashpot for Diesel Generator #12 Turbo-charger Air Inlet Valve, observed on November 27, 1984.

-- P84-6775, Replace makeup valve for #12 Service Water Head Tank (Unit 1), observed on Nov mber 27, 1984.

-- MR 84-4200B, Rebuild and Flow Test Reactor Coolant Pump Seal Assemblies (Unit 1), observed on December 18, 1984.

-- Repairs to #12 Main Steam Isolation Valve.

No violations were identified.

10. Surveillance Testing

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

-- General review of Surveillance Data required to be logged by Operations Personnel, observed on November 30, 1984.

-- STP 0-7-1, Engineering Safety Feature Monthly Logic Test.

-- STP M-171-1, Personnel Air Locks Seal Test.

-- STP 0-73-1, Engineering Safety Features Performance Test.

-- STP 0-1-1, Main Steam Isolation Valve Test.

-- STP M-150-1, Battery Pilot Cell Checks.

-- STP 0-67-1, Check Valve Operability Verification.

-- STP M-200-2, Reactor Trip Breaker Functional Test.

-- STP 0-8-B-2, Diesel Generator and 4KV LOCI Sequence Test.

-- On December 11, the licensee notified the inspector that two of the eight Reactor Trip Breakers (RTBs) on Unit 2 did not meet the licensee's acceptance criteria of 200 msec opening time. Subsequently, the licensee exercised, lubricated and successfully retested the subject RTB's, then returned them to service. The inspector witnessed the retesting of these breakers and subsequently held discussions with the licensee's representatives regarding this matter.

The Accident Analysis in the Final Safety Analysis Report states that the time interval between opening of the RTB and the point at which the Control Element Assemble (CEA) motion begins is allowed to be 0.50 seconds. It also states that a total time interval of 3.1 seconds is permitted between the interruption of power to the CEA holding coil and the point of 90% CEA insertion.

Currently, the licensee "racks the breakers out" monthly and before all startups to test the opening time of the breaker. The acceptance criteria is 200 msec. If the RTB does not meet the acceptance criteria, the licensee exercises, lubricates and retests the breaker until it meets the criteria. This test procedure does not adequately demonstrate the operability of the RTB, in that it does not test the breaker in the "as found" condition. Racking out the breaker requires tripping the breaker. To improve the reliability of the RTBs, the licensee has proposed three RTB design changes. These changes are as follows: (1) to allow for in place testing of RTBs, (2) to upgrade the reliability of the undervoltage mechanism, and (3) to install new RTB front ends where needed. The licensee currently plans to incorporate these changes during the next refueling outage.

In the interim period, the licensee plans to revise the RTB testing procedure to be formally effective January 1, 1985. The revision will increase (double) the testing frequency of those RTBs that do not meet the new acceptance criteria and lower the acceptance criteria time required for the RTBs to open to 100 milliseconds. The licensee also plans to acquire information from other facilities in an effort to compare the in place and "racked out" testing of RTBs. Results of this data will be incorporated into the licensee's test procedure to compensate for any differences in closure time. The licensee has agreed to informally commence these revised testing criteria immediately, and will maintain the testing frequency at an increased interval until the out of specifications breaker completes four successive tests with acceptance criteria of 50 milliseconds. The inspectors periodically observe these tests and will follow their actions. On December 19, 1984 the Plant Operations and Safety Review Committee approved the aforementioned changes to the RTB test procedure.

The inspector had no further questions.

-- During the Unit 1 mini-outage of December 12, 1984, the licensee performed check valve testing of the High Pressure Safety Injection (HPSI) flow lines. During these tests they noted that flows through the lines, although satisfactory for demonstrating the check valves operable, did not meet another requirement of 170 +/- 5 gpm per injection path.

Technical Specification 4.5.2.h requires each of four injection legs be flow balanced to 170 +/- 5 gpm with a single HPSI pump in operation during shut down following work which could change HPSI flow characteristics. Technical Specification 4.5.2.g.(s) requires that when the HPSI system is required to be operable and work is done to the stem or packing of the HPSI Flow Control valves (8), that correct valve positioning is verified by measurement of stem travel.

These two requirements require direct and indirect verification of proper flow adjustment under two different sets of conditions (flow/no flow).

The licensee researched previous "as found" test results and determined that the "as left" 170 +/- 5 gpm data from one refueling interval to the next, generally did not meet the 170 +/- 5 gpm "as found" data when complying with the requirement to check valve stem travel under no flow conditions. Extensive testing was performed which determined that:

-- Four thousandths of an inch of stem travel is equivalent to one gallon/minute flow per valve.

-- When cycling the valve open under no flow conditions the valve opens further by as much as 40-50 thousandths than under flow conditions.

-- Packing adjustments have an effect under no flow conditions, but not under flow conditions, but this is not correlatable.

-- Under flow conditions valve setting and flows are repeatable.

-- With too much flow (approximately 740 gpm total) one pump could "run out"/cavitate.

-- "Run out" could occur if the valves opened too far and the suction fluid temperature was sufficiently high, i.e., under recirculation conditions after a large break LOCA.

-- Two separate initial conditions exist for the valves openings:

(a) With offsite power available; HPSI pump and throttle valves start/open simultaneously (valves open with flow established);

(b) With offsite power not available, HPSI pump is sequenced on approximately five seconds after the automatic opening of the HPSI throttle valves (valves open with little or no flow).

Based on the above, the licensee proposed that setting the throttle valves in accordance with Technical Specification at 170 gpm may violate the safety analysis basis during a loss of offsite power in conjunction with a large break LOCA without any operator action. This is because without onsite power available (i.e., no immediate flow) the valves would open further than previously set with flow giving greater flow initially and perhaps "running out" during the recirculation phase due to the low NPSH and elevated temperatures of the Reactor Coolant.

Resolution of this issue is in two forms:

(a) For the interim, based on the low probabilities of a Large Break LOCA in conjunction with a loss of offsite power and the relatively long period of time available for operator action (at least 35 minutes) to correct improper flow rates, revision of Control Room emergency procedures to instruct operators to verify HPSI leg flows do not exceed 175 gpm (after recirculation commenced), and

(b) Within one month the licensee will implement a change to sequence the valves open and start the HPSI pump simultaneously on both units after the appropriate evaluations.

A commitment to the resident inspector from the Plant Superintendent was documented to this effect in a memorandum dated December 21, 1984. The inspector will follow the licensee's action regarding this item. The licensee stated that this will be reported as a Licensee Event Report (LER) and is considering 10CFR Part 21 report. The resident inspector has submitted this information as a possible generic issue to the NRC Region I.

No violations were identified.

11. IE Bulletin Followup

The inspector reviewed licensee actions on the following IE Bulletin to determine that the written response was submitted within the required time period, that the response included the information requested including adequate corrective action commitments, and that the licensee management had forwarded copies of the response to responsible onsite management. The review included discussions with licensee personnel and observations and review of the item discussed below.

-- IEB 84-03, Refueling Cavity Water Seal. The inspector reviewed the licensee's safety analysis of both a cavity seal failure and the analysis for and procedure use of Steam Generator nozzel dams. These issues were addressed at the Plant Operations and Safety Review Committee meeting No. 84-134 on November 19, 1984. The Calvert Cliffs cavity seal design is somewhat similar to that of the Haddam Neck Plant, however is thicker and "M" shaped, and most importantly is enveloped by nine steel channel seal covers held in place by several clamps. The licensee explained in their analysis that a significant failure of the seal is not creditable, however, goes on to assume a failure of one steel envelope and that segment of the rubber "M" seal. The analysis concludes that radiation levels would be prohibitive, complicating recovery from such an accident, but sufficient time and places in the cavity are available to replace the fuel during a transient, stop the flow from the fuel pool and evacuate if necessary.

The inspector questioned the adequacy of the refueling procedure regarding alarms associated with fuel pool/reactor cavity water levels and radiation levels instrumentation, alarm set points, specific action for each and the allotted time for operator action following a seal failure. Additional NRC inspection guidance has been received regarding this bulletin. This item requires further discussion with the licensee (IFI 317/84-31-02).

12. Radiological Controls

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

No discrepancies were identified.

13. Containment Tendon Surveillance

During routine Unit 1 Containment tendon surveillance testing, the lift off force for hoop tendon 42 H 52 was found to be between the lower expected and lower bound valves. In this situation Technical Specification (TS) 4.6.1.6.1 requires similar testing of the adjacent hoop tendons on either side. Those tendons were checked and found to be in the same value range which constitutes evidence of "possible abnormal degradation of the Containment structure". As required, on November 12, 1984, the licensee entered action statement "A" of TS 3.6.1.6 and began performance of an engineering evaluation to demonstrate the ability of the containment structure to perform its design function. The NRC will follow the licensee's evaluation efforts (IFI 317/84-31-03). TS allow 90 days to complete the evaluation.

14. Review of Periodic and Special Reports

Periodic and special reports submitted to the NRC pursuant to Technical Specification 6.9.1 and 6.9.2 were reviewed. The review ascertained: inclusion of information required by the NRC; test results and/or supporting information; consistency with design predictions and performance specifications; adequacy of planned corrective action for resolution of problems; determination whether any information should be classified as an abnormal occurrence, and validity of reported information. The following periodic reports were reviewed:

-- October 1984 Operation Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated November 14, 1984.

-- November 1984 Operation Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated December 13, 1984.

No problems were noted.

15. Exit Interview

Meetings were periodically held with senior facility management to discuss the inspection scope and findings. A summary of findings was presented to the licensee at the end of the inspection.