U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos. 50-317/84-08 and 50-318/84-08

Docket Nos. 50-317 and 50-318

License Nos. DPR-53 and DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Inspection Conducted: April 11-May 15, 1984

Inspectors: EC Wenzinger for 7/31/84
T. Foley, Senior Resident Inspector Date

EC Wenzinger for 7/31/84
D. C. Trimble, Resident Inspector Date

Approved by: EC Wenzinger 7/31/84
E. C. Wenzinger, Chief Date
Reactor Projects Section 1A

Inspection Summary: April 11-May 15, 1984: Inspection Report 50-317/84-08, 50-318/84-08 Routine resident inspection (157 hours) of the control room, accessible parts of plant structures, plant operations, radiation protection, physical security, fire protection, plant operating records, maintenance, surveillance, radioactive effluent sampling program, refueling activities, and reports to the NRC.

DETAILS

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. Licensee Action On Previous Inspection Findings

(Open) Inspector Follow Item (317/84-07-01) Overheating At Aluminum Bus Bar Bolted Connections In 480 Volt Motor Control Centers (MCC's). As a part of their overall corrective action program for the subject problem, the licensee inspected Unit 2 MCC 201 BT on April 29, 1984. The cabinet cover panels in the vicinity of one bus bar connection were found to be extremely hot. When the enclosing panels were removed, connections for two of the three phases were found to be loose with high measured resistance and showed evidence of overheating. All remaining bolted connections were then tightened as necessary to a torque value recommended by the vendor. Before and after resistance measurements were taken at all connections. With the exception of the two overheated connections, all before torquing resistance readings were low (on the order of 2-15 micro-ohms). Following this second MCC overheating event the licensee committed to the following corrective actions in addition to those specified in Section 3d of Inspection Report 317/84-07; 318/84-07: (1) bolted connection tightness will be checked on all but 3 Unit 2 MCC's during the current refueling outage (the connections in the remaining 3 MCC's had been resistance checked during the last three years); (2) the remaining 3 Unit 2 MCC's and all Unit 1 MCC's will receive similar tightness checks on a priority basis during any available Cold Shutdown(s) of sufficient duration which may occur but not later than the next refueling outage for each respective unit; (3) in the interim, until all connections have been tightness checked, MCC cabinet panels immediately above the bus bars will be checked on a regular basis for temperature increases using a pyrometer (minimum of every six months; frequency to be increased and further evaluations made when highest to lowest readings exceed 10°F).

Since the bus bars are completely enclosed near the top of the cabinets, increases in top panel temperatures would appear to be a reasonable external indicator of overheating conditions.

Unit 1 was shut down on May 6, 1984, due to Component Cooling Water heat exchanger corrosion problems. The licensee initiated tightness checks on MCC 104 but experienced bolt breakage at the torque specified by the vendor. Apparently, the vendor had thought a different type bolt was installed in the MCC's. The licensee committed to obtain proper bolting material and to replace and re-torque bolts in MCC's previously checked and scheduled to be checked.

This item will continue to be followed.

(Closed) Unresolved Item (317/83-07-02) Need To Revise Valve Operability Test Procedures To Indicate That Acceptance Criteria Were Specified By Technical Specifications. The inspector confirmed that valve operability test procedures have been revised to include references to applicable Technical Specifications (TS's) (for response time acceptance criteria). Test procedures revised include:

1. STP 0-65-1, Quarterly Valve Operability Verification-Operating (Revision 24 for Unit 1 and Revision 13 for Unit 2);

2. STP 0-66, Quarterly Valve Operability Verification-Shutdown (Revision 14 for Unit 1 and Revision 18 for Unit 2); and

3. STP 0-9, AFAS Monthly Logic Test (Revision 1 for Unit 1 and Revision 3 for Unit 2).

(Closed) Unresolved Item (317/84-01-02) Need For Licensee To Incorporate Requirements Of 10CFR55.31(e) Into Operator Requalification Program General Instruction Regarding Approvals Necessary Prior To Operator Resumption Of Duties Following A 4 Month Or More Inactive Period. CCI 604 was revised on April 4, 1984, to incorporate 10CFR55.31(e) requirements. It now specifies that NRC approval must be received.

3. 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.

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:

--Diesel Fuel Oil System checked on April 11, 1984 and April 19, 1984.

--Unit 1 Piping Penetrations and Containment Isolation Valves checked on April 19, 1984.

--Unit 2 Salt Water System in Intake Structure checked on April 19, 1984.

--Unit 2 Iodine Removal System and Hydrogen Recombiners inside Containment checked on April 24, 1984.

--Unit 2 Component Cooling Water System. A containment entry was made on April 21, 1984, to view the "as found" condition of the Control Element Drive Mechanism (CEDM) coolers and steam generator support coolers. These coolers utilize water from the Component Cooling Water (CCW) system. The inspection was made during cool down and prior to commencement of the refueling operation, since the CEDM and Steam Generator support cooler supply and return valves are isolated as part of the procedure to gain access to the reactor vessel head per procedure RV-44, "Reactor Vessel Missile Shield Removal", Revision 2, June 4, 1982. Accessible portions of the CEDM and Steam Generator coolers appeared to be in good condition with the valves properly aligned. A significant leak, located somewhere above valve SFP-180, was referred to the licensee for corrective action. During a subsequent containment entry, additional Steam Generator support, reactor vessel support cooler, reactor coolant pump seal cooler valves, and piping were reviewed. These accessible portions of the CCW system appeared to be in good condition. Valves and piping in the vicinity of the reactor coolant drain tank heat exchanger could not be viewed due to the presence of local contamination. In the Unit 2 Auxiliary Building, the east and west penetration rooms, and the MSIV room were entered to inspect the containment penetration coolers which receive water from the CCW system. These coolers and the associated piping and valves appeared to be in good condition. A leak in the vicinity of 2-SI-559 was referred to the licensee for corrective action. Portions of the CCW system located in the letdown heat exchanger room remained inaccessible due to high radiation. This completed the inspection of the CCW system.

--Temporary Fuel Oil Storage. During the present Unit 2 refueling outage the licensee intends to inspect the diesel generator fuel oil storage system. During this inspection, a temporary, 8,000 gallon fuel tanker truck will be connected to the fuel oil storage system such that, at any given time, two fuel oil supplies will always be available. Use of the temporary fuel oil storage facility was addressed in License Amendments 92 and 73 issued by the NRC on April 19, 1984. The procedures for and installation of, the fuel oil tanker truck, were reviewed.

The hook up and use of the temporary fuel oil storage source (tanker truck) is described in CCOM Change Report No. 84-129, dated April 17, 1984. This procedure was reviewed for clarity and technical accuracy and was found to be satisfactory except as follows: (1) an unidentified valve on #11 Fuel Oil Storage Tank (FOST) Low Point Drain/Sample Line, referenced in II.A.5 and IV.A.6 should have been identified by number; (2) an initial condition, "Auxiliary Boilers lined up to #21 FOST" should have been produced as part of the procedure since it involves a non-standard valve lineup (open DFO-108 and close DFO-102). This condition appears in II.A.4, II.A.4, and IV.A.5.

In the course of reviewing CCOM Change Report No. 84-129, it was noted that Drawing OM-79, "Fuel Oil Storage System" was incorrect in that the #21 FOST overflow line does not join the line with sight glass FG-6402. This connection had been removed as part of an earlier modification. These deficiencies were referred to the licensee for correction.

The location and condition of the fuel oil tanker was inspected and found to be satisfactory. The tanker is located adjacent to the fuel oil loading station, is supported by wooden blocks and surrounded by scaffolding. It was recommended that the licensee improve the visibility of the fuel oil tanker in that it is located near a bend in the service road. Warning flags were added to improve visibility.

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 were reviewed. Plant housekeeping and cleanliness were evaluated. Verification of the following tagouts indicated the action was properly conducted.

--Tagout #8566 Salt Water System Sluice Gates checked May 2, 1984.

--The licensee determined that due to an improper Unit 2 diesel generator (DG) equipment electrical lineup on April 26, 1984, Technical Specification requirements for minimum operable electrical buses in Mode 6 were not met for an approximate six hour period. Technical Specification 3.8.2.2 requires at least one emergency 4kv bus to be operable, i.e. energized from a source other than a diesel but aligned to an operable diesel. Due to maintenance on one diesel and unavailability of auxiliary power to a second diesel (#21), neither Unit 2 emergency 4kv bus could be considered operable. Three sources of offsite power were available at the time of the event. Additionally, diesel operability could have been restored in a relatively short period of time through manual realignment of diesel disconnects.

Bus 24A (480v supplied from 4kv emergency bus 24) was removed from service for maintenance at 9:15 p.m. on April 25, 1984. Since Motor Control Center (MCC) 204R receives power from bus 24A and DG 21 auxiliary power is typically supplied by MCC 204R (by interlock auxiliary power for each DG is supplied from the 4kv bus to which that DG is aligned through electrical disconnects), this maintenance action would have rendered DG 21 inoperable. To preserve DG 21 operability, operations personnel shut the tie breakers between MCC 204R and MCC 214R. MCC 214R is supplied from 4kv bus 21.

Oncoming shift personnel were informed of the MCC 204R/214R crosstie, but they apparently did not recognize that the operability of DG 21 now depended on the operability of 4kv bus 21. At 6:25 a.m. DG 12 was taken out of service for maintenance. Without an operable DG aligned to 4kv bus 21, by Technical Specification definition, bus 21 could not longer be considered operable. Similarly, since the auxilaries for DG 21 were being supplied from bus 21, those auxilaries could no longer be considered operable and therefore that DG was, by definition, also inoperable. At this point neither Unit 2 4kv emergency bus met the requirement for operability of TS 3.8.2.2. The action statement of this TS requires that Containment Integrity be established within eight hours.

Because operations personnel did not recognize they were in the action statement Containment Integrity was not established.

At about 4:00 p.m. on April 26, 1984, the operations shift who originally crosstied MCC 204R/214R returned and recognized that the plant was outside the requirements of the TS and its action statement. The situation was corrected by returning #12 DG to service at 9:05 p.m.

In an emergency, as stated above, 4kv bus operability could have been restored in a relatively short period of time by realignment of DG disconnects (DG 21 aligned to 4kv bus 14 and DG 11 aligned to 4kv bus 21).

For corrective action, the licensee plans to (1) prepare lists of equipment required to maintain each DG's operability for use by operations personnel in verifying DG status; and (2) conduct training for all licensed operators on this event with particular emphasis given to the role electrical distribution plays in supporting DG operability.

The failure to meet the TS minimum bus operability requirements is a licensee identified violation meeting the criteria specified in Section IV A, Appendix C, 10CFR2. Therefore, a Notice of Violation was not issued.

4. Review of Events Requiring Prompt Notification to the NRC

The circumstances surrounding the following events requiring prompt NRC notification per 10CFR50.72 via the dedicated telephone (ENS-line) were reviewed.

--At 10:20 a.m. on April 15, 1984, the Unit 2 reactor automatically tripped due to a low reactor coolant flow condition caused by a loss of #22B Reactor Coolant Pump (RCP). The RCP breaker had opened as a result of ground and differential fault protection device actuation. Plant systems functioned as designed following the trip except for the #21 motor-generator set (supplies power to the control element assemblies) which tripped for an unknown reason and a turbine bypass valve (2CV-3940) which stuck open.

Approximately five minutes following the trip the Auxiliary Feedwater System automatically actuated due to a low level in #21 steam generator (the operator had not directed a sufficient amount of feedwater from the main feedwater system to the steam generator following the reactor trip).

The RCP apparently tripped due to a failure of an electrical surge suppressor on phase A. The surge suppressors are capacitors connected near the motor terminals between pump power cables and ground. They are designed to work in conjunction with in-line inductance devices to reduce the rate of rise of electrical surges (such as those caused by pump starts). Reducing this rate of rise helps prevent large voltage differentials between motor windings which can lead to motor damage.

The inspector reviewed the RCP Technical Manual (Manual #12-012 dated July 16, 1974, and an enclosed leaflet #38-421-3, part II) which indicated that voltage limiters ("machine arrestors") are typically installed in parallel with the surge capacitors and function to limit the amount of voltage impressed across the capacitors during transients. The inspector then learned that the licensee does not use machine arrestors with their RCP's. The inspector discussed this with the Plant Superintendent and expressed concern that the capacitors were perhaps being over stressed (by excessive voltage transients) and were therefore failing prematurely. (The licensee has experienced several such capacitor failures during the last four-five years.) The Plant Superintendent stated that they would review the need for machine arrestors. Because of their history of capacitor failures the licensee has tried different capacitor models and plans to replace capacitors periodically (every 4 years). Consideration has even been given to eliminating the surge capacitors entirely.

The NRC will review the event report upon issuance and follow the licensee's progress in resolving the capacitor failure problem and repair of the turbine bypass valve (318/84-08-01).

--With the Unit 2 shutdown for refueling, the licensee took the #22 Component Cooling Water (CCW)/Salt Water (SW) heat exchanger (HX) out of service to, in part, inspect, clean and coat the SW side channel heads with a coal tar epoxy mixture for corrosion resistance. A needle gun was used to clean the inside of the channel heads. On May 3, 1984, this chipping process lead to the discovery of three through-wall holes in the heads which apparently were filled with some form of graphitic corrosion product. One hole was three inches in diameter, the second penetration was oblong in shape (about four inches long and 3/4 inches wide) and the third was about a half inch in diameter. The channel heads are constructed of 2-3% nickel cast iron, A-278 Class 30, material. Prior to removal of the HX from service there was no known external indication of through-wall leakage. There are three similar HX's on the unit (a second CCW and two Service Water [SRW]). The second CCW HX was currently supplying intermediate cooling water to the inservice shutdown cooling water HX. The reactor head was removed with the fuel transfer canal flooded. In the event of a loss of the inservice CCW HX, core cooling could have been accomplished by means of the Spent Fuel Pool Cooling system. Unit 1 was operating at 100% power. Unit 1 has similar CCW and SRW heat exchangers. Typical SW system pressure is about 20 psig. The shell of the CCW HX's is made of welded ASTM A-285, Grade C, steel and is exposed only to relatively pure CCW.

Previously, the licensee had experienced graphitic corrosion problems in varying degrees in circulating water (CW) pump guide vanes and filler pieces, CW water box covers, saltwater pump discharge check valve discs, ECCS (Emergency Core Cooling System) Pump Room Air Cooler SW line duplex strainers, and SW pump front and back heads and volutes. Evidence of graphitic corrosion in CCW channel heads had also been found, which lead to the above described corrective action plan of cleaning and coating the CCW channel heads. The licensee had not anticipated that the graphitic corrosion damage would be so extensive in the channel heads.

On May 4, 1984, the licensee's Plant Operations and Safety Review Committee (POSRC) reviewed the channel head corrosion problem and decided upon a corrective action program. The licensee committed to the following actions: (1) to verify that all equipment located above the Service Water (SRW) and CCW HX's was seismically qualified and mounted; (2) to pull the insulation off the channels heads for all Unit 1 and 2 CCW and SRW HX's and to inspect for leakage (initial inspections to be done by ISI personnel and continuing periodic inspections by operations personnel); (3) to conduct a hydro/leak test (if feasible, the licensee was going to install plugs in the SW lines and hydro the HX's to design pressure); (4) to attempt to qualify an ultrasonics test (UT) procedure to measure true base metal wall thickness (with corrosion product still present) and then check wall thickness on all operating CCW/SRW HX's; (5) to replace all CCW channel heads upon receipt of new heads, and, if necessary, also replace SRW heads; (6) in the interim to minimize elective maintenance to preserve system redundancy, and (7) to consider accelerated plant shutdown (faster than the 72 hours allowed by plant technical specifications) in the event one train's heat exchanger developed a graphitic corrosion related problem.

On May 5, 1984, through-wall seepage was found at the bottom of both Unit 1 CCW HX's (outlet end) near the flange joining the channel head to the HX shell (not far from the tube sheet). Unit 1 was operating at 100% power at the time. The inspector learned of the seepage about 8:00 p.m. on May 5 during a visit to the plant to check progress of HX inspections and UT examinations and then questioned the operability of the HX's. During a subsequent NRC/licensee telephone conference at about 3:00 a.m. on May 6, 1984, the Plant Superintendent stated he would initiate a plant shutdown. Technical Specification 3.7.3.1 requires both CCW HX's to be operable in Modes 1-4 with a six hour shutdown action statement if both HX's should become inoperable. Unit 1 plant shutdown was commenced at 3:10 a.m. As required by the plant emergency response plan for mode changes due to failure to meet T.S. LCO conditions, an Unusual Event was declared at 3:40 a.m. and associated notifications were made. At 8:00 a.m. on May 6, the Plant Operations and Safety Review Committee met and concluded that (1) the Unit 1 CCW HX's should indeed be considered inoperable, (2) that the unit should be placed in Mode 5 with steam generator cooling capability left intact as a backup to normal shutdown cooling and (3) the Unusual Event condition should be terminated upon reaching Mode 5. As of May 8, 1984, the licensee was considering various options for repair/replacement of the CCW channel heads and further evaluating the extent of graphitic corrosion in the SW system. Subsequent removal of corrosion produce in the #12 CCW HX channel heads disclosed 4 through-wall holes. The licensee plans to examine and/or UT a representative sample of all cast iron components (each type component will be examined) in the SW system to assess physical condition and initiate repairs as necessary. The licensee stated that plant startup will not occur until they are satisfied that cast iron SW system components are in an acceptable condition.

Graphitic corrosion is dissolution of the iron in the cast iron matrix by the salt water medium. On May 11, 1984, a region-based inspector examined the condition of the inside of both ends of one Component Cooling and Service Water (SRW) Heat Exchanger (HX) on both Calvert Cliffs Units 1 and 2. The outside of the other, CCHX and SRWHX which were in shutdown service were examined on both units.

The four HXs examined internally were noted to be coated with an organic compound intended to prevent further salt water corrosion of the inlet and outlet cast iron channel heads. Leaks which had occurred on the CCHX heads were sealed with Belzona (brand name) material.

The inspector reviewed drawing 12045-01-1001, sheets #1 and 2 which detail the temporary additional mechanical support for the CCHX channel heads where leaking or ultrasonic wall thickness data indicated a significant below minimum wall condition. The mechanical support arrangement includes external channel head fixturing of the HX tube sheet to both the near and far side channel head flanges and to the channel head pipe flange, captivating the entire channel head.

The inspector reviewed with the site Electric Engineering Department Supervisor the following:

1. Salt water corrosion of cast iron components of CCW and SW heat exchangers.

2. Temporary repairs in progress and planned.

3. The program to establish what other cast iron components may be subject to salt water corrosion.

The inspector concluded that the licensee is aware of or is determining the extent of the corrosion problem and is providing for a repair program on an adequate engineering basis.

--On April 22, 1984 about 12:30 a.m. while realigning the Unit 2 Main Feedwater System (MFW) after completion of special post-modification test of the Motor Driven Auxiliary Feed Pump (MDAFP), steam generator #21 MFW piping suffered a water hammer. The plant was in hot standby with an RCS temperature of 360°F and 400 psig system pressure. The steam generator level was lowered below the feed ring (about the -65 inch level) during the MDAFP test. The feed ring apparently drained through the feed ring/feed water piping coupler during the test. While on auxiliary feed the main feed isolation valve was being opened with the main feed regulating valve and bypass valve closed. No main feed was expected to enter since the regulating and by pass valves were closed.

Leakage past the MFW regulating and/or bypass valve(s) was apparently significant enough to initiate a water hammer. Damage appeared limited to the main feed isolation valve (motor for the limitorque operator was found off and the hand wheel was shattered), main feed regulating valve (air actuator cracked around base at outside circumference) and main feed by-pass isolation valve (yoke at the top of valve was severed at two locations). No external system leakage was found and a walk down of the MFW system and piping constraints outside of the steam generator indicated no further damage. Inspection of the #21 steam generator revealed no MFW feed ring damage. However, the licensee reported that a bolt was found missing from the feed ring thermal liner and that several defective welds were noted on the J-tubes (not related to the water hammer). The inspector confirmed that procedural precautions exist to help prevent future water hammer problems.

Section I of Operating Instruction OI-12A, Feedwater System, Revision 15 dated January 25, 1984, states (Precaution G) that if MFW is not maintained to a steam generator (SG) and concurrently the SG water level drops below -26 inches, the Auxiliary Feedwater System (AFW) must be used to feed the SG's until level rise above -26 inches. Emergency Operating Procedure EOP-1, Reactor Trip, Revision 14 dated February 15, 1984, contains similar guidance. The inspector recommended that similar guidance be added to the procedure in use at the time (Operating Procedure OP-5, Plant Shutdown from Hot Standby to Cold Shutdown). As of April 25, 1984, licensee investigation and analysis was continuing. Licensee evaluation efforts and corrective actions will be followed (318/84-08-02).

5. Observation of Physical Security

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

6. Review of Licensee Event Reports (LER's)

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 | | | |
| 84-04 | 2/28/84 | 3/28/84 | Excessive Charging Pump Packing Failures |
| Unit 2 | | | |
| 84-02 | 3/26/84 | 4/24/84 | Inoperable Radiation Monitor - Required Sampling Was Not Performed |
| 84-03 | 4/15/84 | 5/14/84 | Reactor Trip Caused by Surge Capacitor Failure |

7. 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.

--PM 2-3-6-M-Q-3, #23 AFW Pump Oil Change observed on April 11, 1984.

--PM 2-11-M-A-3, #22 Service Water Pump Coupling Inspection and Lubrication observed on April 11, 1984.

--Repairs to Component Cooling Heat Exchangers observed during weeks of May 7, 1984 and May 14, 1984.

8. Surveillance Testing

The inspector observed parts of a test 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 test was reviewed:

--STP M-20-0, Diesel Generator Inspection observed on May 2, 1984.

9. Refueling Activities

Daily inspection tours of the Control Room and periodic tours of the Containment and Spent Fuel Pools were conducted to ascertain that Technical Specification requirements and industry standard work practice were being implemented. The inspector verified that all applicable Technical Specifications were met relating to refueling.

A review was conducted of applicable Operating Instructions and Surveillance Test procedures, operations log sheets and chemistry logs. Independent radiological surveys and witnessing several fuel transfers were also conducted.

Findings

Technical Specification requirements were met. Work practices and general conduct of operations met industry standards. The inspector noted however one weakness regarding the Quality Controls surrounding the refueling operation.

Although controls of equipment, tools and other items often used around the reactor vessels were established, accountability, lanyards or taping were not required for smaller objects such as pens, dosimetry and badges. The inspector noted that all items potentially capable of being dropped into the reactor vessel or Spent Fuel Pool should be controlled and accounted for, thus minimizing the potential for inhibiting flow to any specific fuel channel during operation.

The licensee acknowledged those observations and immediately instituted corrective action by re-instructing the Quality Control technicians regarding accountability of items around the reactor vessel.

10. Plant Operations and Safety Review Committee (POSRC)

The inspector attended two meetings of the Plant Operations and Safety Review Committee (POSRC) on April 18 and May 6, 1984. The meetings were conducted in accordance with Technical Specification (TS) 6.5.1 and the quorum requirements were met. During the April 18, 1984 meeting the committee reviewed a number of Facility Change Requests (FCR's), Calvert Cliffs Event Reports, Plant Operating Experience Assessment Committee recommendations, plans for fuel assembly sipping during the Spring 1984

Unit 2 refueling outage, and procedure changes. The May 6, 1984 meeting concerned the operability of the Component Cooling (CC) and Service Water (SRW) Heat Exchangers following the detection of graphitic corrosion problems (see Section 4 of this report). In general, committee discussions were effective.

During the May 6 meeting, the committee properly questioned the operability of the CC and SRW HX's and other cast iron components in the Salt Water System.

The inspector reviewed the minutes of the May 6 meeting. Those minutes included a detailed description of the committee discussions and conclusions.

11. Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted pursuant to Technical Specification 6.9.1 and 6.9.2 were reviewed. That review included the following: Inclusion of information required by the NRC, test results and/or supporting information, consistency with design predictions and performance specifications, planned corrective action adequacy 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:

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

--Semi-Annual Effluent Release Report, dated March 1, 1984.

12. 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.