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U. S. NUCLEAR REGULATORY COMMISSION

Region I

Docket/Report: 50-317/84-11 License: DPR-53
50-318/84-11 DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: May 15 - June 12, 1984

Submitted:

for E C Wenzinger

D. C. Trimble, Resident Inspector 6/29/84 date

Approved:

E C Wenzinger

E. C. Wenzinger, Chief, Reactor Projects Section 1A 6/29/84 date

Summary:
May 15 - June 12, 1984: Inspection Report 50-317/84-11, 50-318/84-11.

Areas Inspected: Routine resident inspection (110 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, open items, IE Bulletin Followup, refueling activities, graphitic corrosion in salt water systems and reports to the NRC. One violation was found: Timely Correction of a Root Cause (Valve Labeling).

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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. Licensee Action on Previous Inspection Findings

(Closed) Unresolved Item (318/84-07-01) Assessment of Licensee Corrective Actions to An Inoperable Condenser Vacuum Pump Discharge Radiation Monitor. The inspector reviewed the licensee's event report (84-02) dated April 24, 1984. The report accurately described the event in which the monitor became inoperable due to a detached connector and the follow-on operator/maintenance actions. The event is also described in Section 7 of Inspector Report 317/84-07; 318/84-07. As corrective action the licensee (1) repaired the connector and inspected other radiation monitors for similar problems; (2) will conduct additional operator training on the radiation monitoring system and information will be given on use of the check source function in determining operability; (3) revised control room logs to check all radiation monitor channels once per shift for normal indications; and (4) will perform an engineering review of low level alarm setpoints for the radiation monitoring system. The failure to meet the environmental technical specification requirements for periodic grab samples when the condenser off-gas radiation monitor is out of service is a licensee identified violation meeting the criteria specified in Section IV A, Appendix C, 10CFR2. Therefore, a Notice of Violation was not issued.

(Closed) PAS Item (82-01-41) Delays in Close Out of Maintenance Requests (MR's) Due to MR Not Being Returned to the Senior Control Room Operator (SCRO) and SCRO's Not Completing Testing Requirement Section of MR's. The inspector examined several recently completed MR's to verify proper completion of the Test Requirements Section by SCRO's. No problems were noted. At the time of the PAS inspection, if after work completion plant conditions did not permit testing of the equipment (principally occurred during plant shutdown periods), maintenance groups would hold the MR's open until plant conditions were proper for test. Since those maintenance groups are somewhat removed from day to day plant operations, opportune windows for equipment testing were missed.

The MR procedure, Calvert Cliffs Instruction CCI 200H dated May 1, 1984, now directs that MR's with work completed be turned over to the SCRO, who then is responsible for testing requirements. The inspector confirmed that the SCRO's did not have a large backlog of MR's awaiting operational test. At the time of inspection (June 8) fewer than 10 Unit 2 MR's were being held by the SCRO because the unit was shutdown and proper test conditions did not exist. Those MR's were annotated with information regarding when the test should be conducted (typically in conjunction with a Surveillance Test) and were being checked once per shift. There was no backlog of Unit 1 MR's. The SCRO's were additionally tracking the status of outage work list items (by computer printout) for which they had not yet received MR's for testing. This item is closed.

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:

--Unit 1 Auxiliary Feedwater System checked on June 1, 1984.
--Unit 1 and 2 Nuclear Instrumentation Systems checked on June 1, 1984.
--Spent Fuel Pool Cooling System checked on May 23, 1984.
--Unit 1 Hydrogen Sample System checked on June 5, 1984.

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 tagouts indicated the action was properly conducted.

--Tagout 08736 No. 11 Auxiliary Feedwater Pump checked on June 1, 1984.
--Tagout 08930 Spool Piece Installation, No. 11 Spent Fuel Pool Cooling System checked on June 23, 1984.

d. Other Checks

At 6:40 a.m. on May 31, 1984, during a plant startup on Unit 1, operations personnel discovered that the Narrow Range Nuclear Instrumentation (NRNI) Channel A was reading 3% power while Channels B, C, and D indicated about 7% power. At the time the operators had been directed to maintain the plant in Mode 2 (less than 5% power) and a containment vent (through the Containment Sump drain line) was in progress. During such containment vents the sump alarm is considered to be inoperable and the licensee enters the action statement of TS 3.4.6.1 (Reactor Coolant leakage detection systems). TS 3.0.4 does not allow mode changes while in an action statement. Because power had increased, however, to 7% a mode change had been made. Power was immediately reduced to less than 5%. The cause of the Channel A error was a loose amphenol connector on the back of the cabinet.

At low power levels (0-5%) installed narrow range indicators on 1C04 read at the low end of the scale and actually read the higher of flux or delta T power (not simply nuclear flux). The wide range (WR) nuclear flux indicators read on logarithmic scales which have divisions only for 1, 5, and 10% power (in this part of the scale). Therefore, nuclear flux power is not as easily read as it is at higher powers. Also, differences between channels are not as easily recognizable as they are at higher powers. Therefore, operators select Channel A nuclear flux (the only narrow range nuclear instrumentation channel read by the computer) to a trend recorder and monitor flux off of this recorder for more precise indication. Since Channel A was not functioning properly, the operators had a false indication of core power.

The operators began investigating the problem when they received an alarm indicating a high difference between the Channel A upper and lower detectors. Had the situation continued additional alarm warnings would have keyed the operators into the problem (hi and hi-hi deviation alarms between flux monitoring channels at 10 and 15%; deviation alarm between nuclear and delta T power at +/- 3%).

The licensee has tentatively concluded that the event was partially caused by a lack of appropriate controls and guidance in operating procedures combined with a failure of the operator to perform a periodic review of equipment indications. To prevent recurrence, they plan to modify the plant startup procedure as follows:

(1) provide direction that Mode 1 be declared based on the highest power indication, and

(2) require that periodic inter-channel comparisons be made to determine the highest indicating channel prior to reaching Mode 1.

Furthermore, they plan to conduct training on the event during the annual operator requalification cycle.

The licensee entry into Mode 1 without meeting the requirements of TS 3.0.4 is a licensee identified violation meeting the criteria specified in Section IVA, Appendix C, 10CFR2. Therefore, a Notice of Violation was not issued.

On June 5, 1984, authorization was given (lifted wire # 2-84-45) by the Shift Supervisor for lifting a wire to solenoid valve (0-SV-6507) for the Hydrogen (H2) Sampling system. That valve is located at the discharge of the sample pump (also called moisture separator pump) for H2 analyzer 1C139 and, when open, directs the sample return to the Unit 2 Containment. The valve is an energized to open valve and lifting the lead would prevent valve opening. A second solenoid valve (0-SV-6509) on the pump discharge functions to direct the sample return to either the Unit 1 Containment or the plant vent, depending on downstream valve alignment. The plant has a second, identical H2 analyzer (1C140) with similar pump discharge valves (0-SV-6550 directs sample return to Unit 1 Containment/plant vent; 0-SV-6528 directs sample to Unit 2 Containment). The reason for installing the lifted wire was to prevent any passage of sample gas through the return line to the Unit 2 Containment while downstream isolation valves were being replaced. A second lifted wire procedure was to be followed for the second analyzer later in the day to prevent its discharge from going to the Unit 2 Containment.

The technician who researched the technical drawings (Vendor Print Nos. 02332 Sheet 3 of 4, Revision 3, and 02320, Revision 5; BG&E Print No. OM463, Revision 2, Sheet 2 of 2) had difficulty correlating vendor print valve nomenclature and the BG&E print nomenclature. The vendor print labeled the pump discharge valves on each cabinet as SV-12 and 13, whereas the plant drawing labeled the valves 0-SV-6507 and 0-SV-6509 for 1C139 and 0-SV-6528 and 0-SV-6550 for 1C140. Additionally, the pump discharge valves themselves are not adequately labeled in their cabinets. This situation forced the technicians to trace sample lines inside and outside the cabinet which is difficult and potentially confusing in that there are other lines in the area. Principally, due to these problems, the technicians actually disabled valve 0-SV-6509. Unit 1 was in Mode 1 at the time and Unit 2 was shutdown in a refueling outage. The Unit 2 Containment isolation valves for the H2 sample return had not yet been taken out of service and analyzer 1C140 was still operable. This action limited the capability of analyzer 1C139 in that it could not sample the Unit 1 Containment and return the sample to that same building (the preferred flow path). Technical Specification 3.6.5.1 requires both H2 analyzers to be operable during Modes 1 and 2 with a 30 day action statement when one analyzer becomes inoperable.

The lifted wire error was found later in the morning by a technician researching the above prints for lifting the lead to 0-SV-6528 to complete preparations for the Unit 2 Containment valve replacements. At 10:15 a.m. on June 5, the lead was replaced to 0-SV-6509.

In February of 1984 a problem with an improper tagout of Oxygen Analyzing System Sampling valves due to inadequate valve labeling (labeling on the valves different from labeling on the plant drawing and in the operating instruction) was the subject of a violation (317/84-03-03). The H2 analyzer event appears to be an additional symptom of a basic valve labeling problem in the Gas Analyzer cabinets. To date, this labeling problem has only been observed in these cabinets. In general, licensee labeling of plant valves is good and has been discussed in previous reports. The licensee's response for violation 317/84-03-03 did not specifically mention corrective action in the area of valve labeling improvements. The licensee previously recognized deficiencies in plant component labeling and in 1982 embarked on a system verification/valve labeling program. Significant labeling improvements have been made. On a long term basis the licensee plans to label all valves shown on plant OM drawings. As discussed above, however, labeling had not yet been completed for the H2 analyzing system. In February of 1984 a problem with an improper tagout of Oxygen Analyzing System sampling valves due in part to inadequate valve labeling (labeling on valves was different from labeling on the plant drawing and in the operating instruction) was the subject of violation (317/84-03-03). Following this event, the licensee did not accelerate their Gas Analyzing System valve labeling schedule and thereby provide prompt corrective action for an identified deficiency. Prompt action in this area could have prevented this second event. This a violation. (317/84-11-02)

4. Observations of Physical Security

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

5. 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			
84-05	5/03/84	6/02/84	Saltwater System Graphitic Corrosion
Unit 2			
84-04	4/21/84	5/18/84	Main Steam Safety Valve Setpoints Out of Tolerance
84-05	4/26/84	5/24/84	Diesel Generator Inoperable

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 317/84-05 is discussed in Section 9 of this report.

6. 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.

--MR 0-84-2663 Installation of Spool Piece in Discharge Piping of No. 11 Spent Fuel Pool Cooling Pump observed on May 23, 1984.

--Repair/Replacement of Component Cooling and Service Water Heat Exchanger Channel Heads observed May 15-29,1984.

7. 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 510-2, RPS Calibration Check (Revision 8) observed on June 6, 1984.

8. IE Bulletin Followup

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

--IEB 82-02 Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants. The licensee conducted the inspections of threaded fasteners required by Item 2 of this bulletin and reported the results in letters dated March 17, 1983 (for Unit 2) and March 30, 1984 (Unit 1). As a general summary, those inspections revealed problems in only Unit 2 Steam Generator manway studs (pitting). Affected studs were replaced. These letters also reported that actions required by Item 1 had been taken (procedure upgrades to ensure proper training in bolting practices, detensioning/retensioning practices, and gasket installation and controls).

The licensee responded to Item 3 regarding history of leakage experiences, inspections, corrective actions, use of lubricants, and composition of lubricants) in a letter dated July 30, 1982. The bulletin stated that reactor vessel head closure studs were excluded from the scope of the bulletin for licensees committed to Regulatory Guide (R.G.) 1.65, Materials and Inspection for Reactor Vessel Closure Studs. On October 1, 1982, the licensee stated how they met the intent of R.G. 1.65 and provided technical information to support their position. The licensee's efforts were responsive to the bulletin action items and appear complete. This bulletin is closed.

--IEB 83-08 concerned electrical circuit breakers with an undervoltage (UV) trip feature in use in safety related applications other than the reactor trip system. On March 21, 1984, the licensee reported that the types of UV trip mechanisms of concern in this bulletin are not used in safety related equipment (other than the reactor trip system) at the Calvert Cliffs facility. Therefore, no further action was required. This bulletin is closed.

9. Graphitic Corrosion in Salt Water Systems

A meeting was held with licensee management and engineering personnel on May 17, 1984 to discuss managerial and technical aspects of the graphitic corrosion problems described in Section 4 of Inspection Report 317/84-08; 318/84-08. The results of that meeting will be documented in separate correspondence.

The licensee repaired the channel heads for the #12 and #22 Component Cooling Water (CCW) heat exchangers and the #12 and #22 Service Water (SRW) heat exchangers. Licensee examinations of other cast iron components in the salt water (SW) systems and further review of minimum wall thickness requirements for salt water pump casings determined that component operability was only questionable for the #22 SW pump. Strain gauge measurements were made for #22 SW pump casing with the ultimate objective of confirming its operability. During the period of May 14-23, while the operability of the SW pumps was under evaluation, the licensee conservatively declared those pumps (and therefore the SW system) inoperable and ceased fuel handling operations on Unit 2.

New channel heads made of carbon steel were installed on #11 and #21 CCW heat exchangers. No. 11 and 21 SRW heat exchanger channel heads were found to have acceptable wall thickness and repairs were not necessary. All cast iron CCW and SRW channel heads still in service were cleaned (corrosion product removed). All CCW and SRW channel heads were coated with coal tar epoxy. Additional sacrificial anodes will be added to the new CCW channel heads.

Unit 1 was restarted on May 30, 1984.

The licensee committed to replace the remaining cast iron CCW channel heads and #12 and 22 SRW heat exchanger channel heads on both units during the first shutdown of sufficient duration (a shutdown of about one week duration would be required). Additionally, the licensee will inspect each channel head after one month's operation to verify the coal tar epoxy coating is in tact and quarterly thereafter. Plant operators are to inspect repaired channel heads once per shift for leakage and report any leakage to the General Supervisor-Operations and/or the Plant Superintendent. If leakage on a channel head reaches 5 gpm that heat exchanger will be considerable inoperable. Finally, the licensee installed spray shields around repaired channel heads to prevent spray on susceptible components in the event leakage should develop.

Licensee commitment actions will be followed (317/84-12-01).

10. Refueling

On May 24, 1984, the inspector observed fuel handling evolutions from the Containment Fuel Handling bridge. The bridge was operated by a licensed Reactor Operator and the evolution was being directly supervised by a licensed Senior Reactor Operator. The inspector confirmed that Technical Specification requirements regarding neutron flux monitors (TS 3.9.2), Containment penetrations (3.9.4), direct communications (3.9.5), and water level over the vessel (3.9.10) were met. No discrepancies were identified.

On May 29, 1984, the inspector attended one of the licensee's daily Unit 2 outage meetings. The status of major jobs was reviewed with representatives of the various onsite work groups. The meeting was conducted efficiently.

During the current Unit 2 refueling outage the licensee conducted fuel sipping operations (first priority was to sip fuel assemblies which would be reused during Cycle 7 operation) to identify leaking assemblies. Early in Cycle 6 the licensee had noted a step increase in Reactor Coolant activity. Activity then remained relatively constant at the elevated level with periodic iodine spikes following plant transients. Iodine-131 spikes above 1 microcurie per gram were appropriately reported in Licensee Event Reports which attributed the spikes to a very small number of leaking fuel pins in combination with power level transients. Further examination of assemblies which showed leakage (by sipping) revealed one damaged pin in each of four assemblies. The damage in bundles G21 and G003 was minor and located about two inches from the bottom (apparently fretting type damage). In bundles G22 (18 inches from the top) and G121 (50 inches from the bottom) the affected pin was significantly damaged with clad openings large enough to permit, in one case, the loss of about four fuel pellets and, in the second case, the loss of two or three pellets. All four damaged bundles were from the same fuel batch and had just completed their first cycle. G22 and G121 were in high flux areas. Their symmetric assemblies were not apparently similarly damaged. The mechanism of damage in these later two assemblies has not been determined, but, as mentioned above, probably occurred about the same time early in core life.

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:

--April 1984 Operation Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated May 15, 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. No written material has been provided to the licensee during the preparation of this report.