U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/Report Nos.: 50-317/88-07 License Nos.: DPR-53
50-318/88-08 DPR-69

Licensee: Baltimore Gas and Electric Company
Post Office Box 1475
Baltimore, Maryland 21203

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

Inspection At: Lusby, Maryland

Inspection Conducted: April 1 - May 16, 1988

Inspector: D. Trimble, Resident Inspector

Approved By: Lowell E. Tripp 6/3/88
Lowell E. Tripp, Chief Date
Reactor Projects Section No. 3A

Summary: April 1 - May 16, 1988: Combined Inspection Report Numbers 50-317/88-07 and 50-318/88-08

Areas Inspected: (1) facility activities, (2) operational events, (3) refueling outage, (4) maintenance, (5) surveillance, (6) radiological controls, (7) physical security, (8) Licensee Event Reports, (9) reports to the NRC, and (10) licensee self-identification of problems.

Results: Two violations were identified. One involved a failure to submit a report required by Technical Specifications (TS) on the required schedule (Detail 11). This is a repeat problem. The second involved the making of a temporary change to a surveillance test procedure without first obtaining TS required approvals (Detail 7). There were a number of indications that the licensee was not sufficiently prepared for the Unit 1 refueling outage, resulting in problems that potentially could have been avoided (Detail 4). Controls over valve lineups for a subset of plant valves/systems appear weak in that responsibilities for control are not clearly defined. This may have contributed to an incident in which the primary and one of two backup sources of breathing air were lost to a diver (Detail 3). A maintenance error caused significant damage to a Low Pressure Safety Injection pump and jeopardized pump operability (Detail 5). This in combination with two other apparent maintenance errors that were identified immediately following this inspection period (over torquing of steam generator primary manway covers and improper wiring of a torque switch on a motor operated valve) indicate weakness and will be further reviewed in the next inspection period. The licensee is becoming increasingly proactive in identifying existing problems and safety concerns (Detail 12). This is a positive trend.

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DETAILS

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. Weekend inspections were performed on April 10, 1988.

1. Summary of Facility Activities

Unit 1

The unit began the period operating at power and was shut down for a refueling outage on April 8, 1988. The unit remained shut down for the duration of the inspection period.

On May 2, 1988, four spurious trips of the Engineering Safety Features Actuation System were experienced while modifications were being performed on the system (Section 4) of this report.

Unit 2

The unit began the period performing a plant startup following a four and one-half week maintenance outage. On April 27, 1988 the unit tripped on low steam generator level from 100% power following the loss of #21 Main Feed Water (MFW) pump (details in Section 3 of this report). Unit 2 returned to power operation on May 2 and remained at power for the duration of the inspection period.

General

On April 25, a high ranking Soviet delegation visited the site for a tour and discussion with the licensee and NRC. One purpose of the Soviet visit to the United States was the signing of a Memorandum of Cooperation in the nuclear safety area.

On May 2, the licensee met, along with representatives of other utilities, with the NRC in Rockville, Maryland to discuss industry responses to Generic Letter 87-12, "Loss of Residual Heat Removal While the Reactor Coolant System is Partially Filled".

On May 2, the Vice President, Nuclear Energy moved his headquarters from the Baltimore Corporate Office to the site.

On May 2, the licensee met with the NRC in Rockville, Maryland to discuss a problem regarding improper settings of relief valves.

An INPO team visited the site during the period to review outage activities.

2. Review of Plant Operation - Routine Inspections (71707)

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, effluent monitoring, emergency power source operability, control room logs, shift supervisor logs, and operating orders.

-- During a tour of the Unit 1 containment the inspector noted that the lights on the polar crane did not have protective screening installed that would function to prevent pieces of glass (if the bulb should break) from falling into the open reactor vessel. In discussion with licensee personnel the inspector learned that this had been brought up previously as a personnel safety hazard. In fact, whole light fixtures have fallen from the crane in the past. The licensee stated they would relook into the issue and agreed with the concern.

b. Biweekly and Other Inspections

During plant tours, the inspector observed shift turnovers; 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.

-- Housekeeping in the #12 Reactor Coolant pump bay was poor, i.e., general area very dirty, poorly lighted, cluttered step off pads, and overflowing bags of protective clothing. This was brought to the attention of the licensee.

No other unacceptable conditions were noted.

3. Operational Events (93702, 92700 and 90712)

Four Spurious Actuations of the Engineered Safety Features Actuation System

See Section 4 of this report for details.

Introduction of Excessive Air Into Reactor Coolant System During Shutdown Cooling

On April 11, 1988, with Unit 1 shutdown for refueling with the reactor vessel head still installed on the vessel, operators conducted a procedure to "blowdown" the primary side of the steam generator tubes (i.e., get out the water trapped in the tubes) using plant air through instrument sensing line penetrations. The pressurizer was vented at the time. Initially the water level was at the 20 inch point which corresponds in elevation to the top of the reactor vessel head. Therefore the reactor vessel and head were full of water. The shutdown cooling system was in operation. A revised procedure for the blowdown operation was being used for the first time. This procedure was written with the understanding that at the time the blowdown operation was begun operators would have, as a part of the normal plant cooldown and RCS drain procedure (Operating Procedure OP-5, Revision 30) opened the manual reactor vessel head vent valves, 1-RC-274 and 275. Operators, however, began the blowdown procedure before the vents were opened. This was due to a procedural weakness in that the step calling for the tube blowdown (per Operating Instruction OI-1A, Revision 13) immediately preceded the step requiring the vents to be opened. Only by careful reading of the OP would one recognize that the steps should be carried out concurrently.

Air was admitted to tubes for steam generator #11. By procedure, air was to be admitted until pressurizer level increased to 265 inches (volume increase of about 7350 gallons). That corresponded to the volume of water believed to be held in one steam generator's tubes.

The reactor coolant system (RCS) was then drained back down to a pressurizer level of 20 inches. Then the tubes were blown for #12 steam generator. Again the RCS was drained to 20 inches pressurizer level.

At this point (about 4:00 p.m.) a flange on top of the reactor vessel (at the penetration for a reactor vessel level monitoring probe) was beginning to be disassembled, and air vented through the flange. Reactor coolant system level indication in the Control Room dropped rapidly to zero. The low suction pressure alarm for the #11 Low Pressure Safety Injection (LPSI) pump, which was running, began to intermittently alarm. LPSI pump current did not oscillate. Operators started #12 charging pump and opened the suction valve for the LPSI pump to the Refueling Water Tank, and opened the solenoid operated vessel head vent valves. Water was added to the RCS until level returned to the 20 inch level in the pressurizer. The licensee estimated that this took 12,761 gallons.

The inspector subsequently calculated that the volume of water between the top of the hot leg and the top of the vessel head is approximately 10,000 gallons. The licensee confirmed this number. The volume from the mid point of the hot leg to the top of the hot leg is about 5,000 gallons. Based upon the physical construction of the RCS, excess air injected for the #11 steam generator tubes that gets in the hot leg would pass up the surge line, into the pressurizer and out the vent. Excess air from #12 steam generator that goes into the hot leg would tend to migrate toward and probably collect in the vessel head. It's not clear where excess air in the cold legs would collect. The LPSI pumps take suction off of the hot leg to #12 steam generator.

It appeared to the inspector that an excessive amount of air was blown into the steam generators and enough air collected in the vessel head region to displace water level down to approximately the top of the hot legs. Further depression of vessel level is doubtful because additional air collecting in the hot leg would be vented off through the pressurizer vent. Prior to the venting of the head, pressurizer level was reading falsely high due to the presence of the air bubble in the vessel. During the venting, water level in the pressurizer dropped to some point in the surge line, and water level rose somewhat in the vessel. The 12,000 gallons of water were required to refill the vessel head, the surge line, and the pressurizer to its 20 inch level. The licensee agreed that this was the most likely scenario.

The inspector expressed concern that excessive air blown into the RCS could enter the suction of the LPSI pump through the vortexing effect described in Generic Letter 87-12, "Loss of Residual Head Removal While the Reactor Coolant System Is Partially Filled", and possibly jeopardize shutdown cooling. Therefore, that air should more carefully be controlled. Additionally, he agreed with the licensee that the procedure was weak in addressing when the vents should be opened.

By the close of the inspection period the licensee had appropriately modified OP-5 and OI-1A and placed a description of the event in the operator required reading file.

Loss of Breathing Air

On April 21, 1988, breathing air was lost to the Unit 1 containment while a diver using the air was working in the refueling pool. An emergency supply of air was placed on line by a second diver on the side of the refueling pool and the diver in the water returned safely to the surface. Breathing air is fed from the non-safety related plant air (PA) system. In case normal PA is lost, the containment PA and breathing air headers can be isolated from the upstream PA system by shutting control valve 1-CV-2026 and then supplied by emergency air bottles by opening valve 1-CV-2031. Between 1-CV-2031 and the emergency air bottles, there are two air regulators in series and a manual isolation valve.

During the dive a carbon monoxide (CO) monitor on the plant air header alarmed. The CO alarm was probably due to a significant amount of welding/burning in the vicinity of the plant air compressor air suction. As directed by procedure in this situation, operators repositioned hand-switch 1-HS-2026 which isolates (shuts 1-CV-2026) normal PA to the containment and opens 1-CV-2031 to supply air from the bottles.

Valve 1-CV-2031 would not open because it was improperly gagged shut. One of the pressure regulators (1-PCV-2029) had been replaced recently and was not adjusted properly. Therefore, air was lost to the diver. Fortunately the diver had an emergency air supply near the refueling pool that was then placed on line.

Maintenance had been performed recently (January 18, 1988) on 1 PA 2029. On April 15, 1988, an air set and solenoid were replaced on 1-CV-2031. The technician working 1-CV-2031, also recalled seeing mechanics working on one of the upstream components that same day. The technician stated he did not gag 1-CV-2031 during his work and that the valve freely cycled as air was sequentially lost and then regained to the valve operator during the repair. Existing tagouts for this part of the system were cleared later on April 15. Post maintenance testing for 1-CV-2031 was performed satisfactorily on April 17. The valve was cycled during the test. On April 19, a "mechanical devices" control document was approved (control #1-88-52) which was to be implemented in stages as part of a modification to upgrade the air system. No control tags were issued for the valves in question, however a remark was attached saying "While piping in the system check valve the following Instrument air loads are lost ... 1-PCV-2027 (air regulator), 1-CV-2031, and 1-CV-2026. Breathing air control. Plant air valve to containment should be gagged open. Breathing air bottles should be isolated. No person should be using breathing air."

The licensee has investigated the event but to date had not been able to identify how 1-CV-2031 was gagged and the PCV improperly adjusted or to establish a connection between the gagging and the above "mechanical device" control document.

The licensee believes, however, that the problem may have been caused by the fact that more than one plant group is involved in the control of the PA system lineup and that the demarcation point or limits of each group's responsibility for control is not clear. This is unusual. Normally operations personnel are strictly in charge of system lineups. In this case, radiation controls personnel, who are in charge of the respiratory protection program and therefore breathing air, share control over the system. For example, radiation controls personnel periodically must isolate the emergency air bottles from the PA system in order to refill or change out bottles. Bottles are isolated at times to prevent their bleeding slowly back into the PA system, which necessitates bottle recharging.

This sort of joint control and lack of demarcation apparently has also caused confusion in at least two other areas, feedwater demineralizer system (operations and water treatment groups) and instrument root stops (operations and instrument and controls groups).

The licensee stated they have been trying to clarify these responsibilities. The licensee committed to continue efforts in these areas until resolution is achieved.

Unit 2 Reactor Trip

At 8:48 a.m. on April 27, 1988, Unit 2 tripped from 100% power due to low steam generator level following the loss of #21 main feedwater pump (MFWP). The exact cause of the MFWP trip was not determined. Number 22 MFWP tripped on high discharge pressure following the loss of #21 pump. There was indication that the cause of #21 MFWP trip may have been a malfunction in the thrust bearing wear monitor which can generate a pump trip. The trip function of the monitor was removed from service. Pump trip circuits are now being monitored by a temporary recorder. All other pump trips were checked to verify they were functioning properly. It is believed #22 MFWP tripped because, as the main feedwater regulating valves began closing following the reactor trip (as they are designed to do), the MFWP recirculation valve to the condenser failed to open fast enough and lead to a high discharge pressure condition. Upgrades of the recirculation valves are planned.

The unit was returned to power on May 2, 1988. Initially power was restricted to 70% which is the maximum power at which a MFWP trip can be tolerated without causing a unit trip. The pump performed properly and the unit was returned to full power.

Following the above trip a main steam line hanger on the 69 foot elevation in containment (#31EB1-2005H2) was found cracked and required repair prior to unit startup. The failure was initially believed to be due to cyclic fatigue; however further analysis is required to confirm this mode of failure. The licensee plans to relook at the adequacy of the design of the hanger. The licensee has experienced several failures of main steam hangers in containment and has upgraded those hangers. This hanger had failed once before. The inspector will review license actions with regard to improvement of the design of this hanger during a future inspection.

4. Unit 1 Refueling Outage (37700 and 93702)

Apparent Insufficient Preparation for Unit 1 Refueling Outage

During the period there were several indicators of insufficient licensee preparation for the Unit 1 refueling outage.

On the afternoon of May 2, 1988, four spurious trips of the Engineered Safety Features Actuation System (ESFAS) were experienced. The plant was in refueling (Mode 6) at the time and ESFAS was not required to be operable. No water was injected into the reactor coolant system. Some equipment actuations occurred, such as diesel generator starts, but this did not cause significant problems. Multiple modifications were being made to ESFAS at the time, and activities associated with these modifications caused the trips. Ultimately the ESFAS actuation cabinets were purposefully deenergized to avoid further trips and allow technicians to determine the root cause and take corrective actions.

Six modifications were in progress at the time which were being carried out by the same group of individuals (electrical and instrument modifications group) either in the same general area or on equipment associated with ESFAS. They were: 1) Facility Change Request (FCR) 88-150, wide range nuclear instrument upgrade from combination of proportion counter/fission chamber combination to ganged fission chambers which included change out of certain containment electrical penetrations; 2) FCR 88-35 which replaced electrical cable to several components in containment including, on the date of the event, pressurizer pressure instrument cabling; 3) change out of the pressurizer pressure transmitters from Barton to Rosemont transmitters; 4) FCR 88-153 installation of ATWS (Anticipated Transient Without Scram) modification; 5) FCR 83-1029 installation of a new plant computer; and 6) upgrade of instruments on Control Room panel 1C06 to install instruments to meet Regulatory Guide 1.97 requirements and to include human factors improvements.

The first two actuations, at 2:12 p.m. and 2:30 p.m. were due to similar circumstances. ESFAS Channel ZE was down powered for ATWS modification, giving one low pressurizer pressure signal to actuation cabinets A and B. ESFAS requires 2 of 4 signals to actuate. Simultaneously personnel were changing out cables to two pressurizer pressure transmitters (PT), Channels ZF and ZG, for EQ upgrade. The PT loops unwisely had not been deenergized during this change out. Cables for ZF and ZG PT's were connected back into their respective circuits. The PT ends of the cables at the time were shorted. Full loop currents resulted causing Channels ZF and ZG to indicate high pressurizer pressure. Two of four pressurizer pressure transmitters registering high pressure causes an ESFAS block (to prevent safety injection actuation on low primary pressure) to clear. Because Channels ZD and ZE were reading low pressure at the time, a 2 out of 4 signal for safety injection actuation (SIAS) was sent to both actuation cabinets.

The PT circuits were then opened by slide links to prevent recurrence. The last two events were caused by faults in the ZE cabinet associated with a small portion of the cabinet which was energized. These were due to wire connectors which had either broke or slid off their pins during ATWS modifications. These caused momentary current surges to the A actuation cabinet +15 volt power which caused A train actuations.

The inspector and licensee independently concluded that when various FCR's are being implemented simultaneously more up-front planning and scheduling needs to be done to properly sequence tasks. A principle reason this was not done better was that at least two of the modifications did not reach the shop until shortly before or at the beginning of the outage (ATWS and EQ cables).

The licensee also concluded that such work, whenever possible, should be performed with the actuation cabinets de-powered; ESFAS SIAS trip setpoints should be reset to zero to prevent such actuations; during cable replacements transmitter side leads should be separated and taped; and that prior to unit startup an inspection of pin terminations should be performed.

Aside from the ESFAS events there were other indications of insufficient preparation. A review of an FCR to install new actuations on charging system valves 1-CV-517, 518, and 519 was not conducted until shortly before the outage and that review identified a significant error in considering the effects of the added weight on system piping stresses. New supports were suddenly required. Late parts, particularly the spring cans associated with installation of mud legs on the Auxiliary Feedwater System steam piping, held up work.

It appeared that the Unit 2 maintenance outage recently completed, although very beneficial with respect to identifying and fixing Unit 2 problems, overly distracted resources needed to prepare for the Unit 1 outage.

Failed Fuel Assembly Pins

During the Spring 1988 Unit 1 refueling outage the licensee performed ultrasonic inspections of all fuel assemblies. The assemblies are manufactured by Combustion Engineering. Pins with suspected deficiencies were then eddy current tested. Four leaking pins were identified. These pins were replaced with solid, stainless steel pins. Three fuel assemblies were involved. These had all been used for just one cycle. Two of the failed pins were in a peripheral fuel assembly (IL014). These pins were on the outside of the bundle (and very outside of core) and were damaged by debris in the vicinity of their bottom end caps in the first 1/2 to 1-1/2 inches of their length. Some fuel pellets could have escaped. The piece of debris consisted of a approximately 2-1/2 inch long, straight, 3/16 inch thick piece of metal which entered the fuel assembly through the bottom flow plate. The piece remained trapped in the cage of the fuel assembly after the affected pins were removed, necessitating the transfer of all pins in the assembly to a new "cage". The assembly was a low power assembly and there was no evidence of secondary hydriding of the pin.

Two additional pins (one pin in each of two other assemblies) were also damaged. These assemblies (IL101 and IL108) were located in a relatively high power region of the core near the center. The two assemblies were in locations symmetric to each other. These were not the hottest rods in the assemblies. One is known to have failed by some other mechanism than debris. The failure mechanism of the second pin has not been evaluated. There was more secondary hydriding in these pins. Other pins in the area were examined, and no degradation was found. Again, there is a possibility fuel pellets could have escaped from these pins. One of the pins had a small area in which 70% of the clad circumference was missing. The licensee is further evaluating the cause of failure of these two pins.

5. Plant Maintenance (62703 and 93702)

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, fire protection, retest requirements, and reportability per Technical Specifications. The following activities were included:

-- Fuel handling in Spent Fuel Pool, April 25, 1988

-- Replacement of yoke on 1-MOV 652, May 3, 1988

-- Retubing of #12 SRW Heat Exchanger, May 5, 1988

-- Repacking of casing drain valve (1-MS-504) for #12 AFW Pump, May 10, 1988

Weakness in Design of Low Pressure Safety Injection (LPSI) Pump Seal

During the Unit 1 refueling outage, the mechanical seal for #11 LPSI pump was replaced. The pump was then tested and declared operable. After running for about a day, the new seal failed. The inspector learned from licensee maintenance personnel that these seals are difficult to install properly and frequently require rework after replacement. A Facility Change is in progress to change to a new type of seal which will be easier to install.

To the licensee's credit, following the above #11 LPSI seal failure and repair, the General Supervisor, Operations (GSO) required the pump to be run for 24 hours prior to being declared operable to gain confidence in seal performance. This came at a point in the outage schedule where such a test delayed "critical path" evolutions and therefore demonstrated commitment by the licensee to ensure work is properly completed.

Maintenance Error

The licensee identified through its equipment vibration monitoring program that vibrations were high on #22 Low Pressure Safety Injection (LPSI) Pump. Further investigation showed that the motor/pump coupling had not been properly filled with grease following an overhaul of the pump in April 1987. Gear teeth in the coupling were badly damaged. The principle cause appeared to be inattention to detail by maintenance personnel. This is a licensee identified violation pursuant to 10 CFR 2, Appendix C, Section V (50-317/88-07-01;50-318/88-08-01).

During coupling disassembly a significant amount of misalignment was found between pump and motor shafts. The inspector recalled that significant problems were experienced by the licensee during 1987 with this LPSI pump. These included a "cold spring" condition in the pump suction piping, motor/pump alignment problems, mechanical seal leakage, and motor vibration due to inadequately supported base plate. The inspector expressed concern that the root cause of the current misalignment may not have yet been identified. He asked the licensee to consider further testing of the pump with a follow on recheck of coupling alignment to gain further confidence that the coupling will stay in alignment. The licensee agreed to perform this test when plant conditions permit. The inspector noted that a planned maintenance activity was scheduled within the next 2 weeks which would disassemble, clean, and replace the coupling for #21 LPSI pump.

During the week following the close of the inspection period, two additional problems occurred which were apparently due to maintenance errors, i.e., over torquing a steam generator (primary) manway and improper wiring of a torque switch for motor operated valve 1-MOV-403 which is the blocking valve for one of the PORV's. These will be discussed in further detail in the next inspection report.

6. Surveillance (61726 and 61720)

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 test was reviewed:

-- STP M-571-1 Local Leak Rate Test of 1-MOV-6200, May 10, 1988

On April 2, 1988, the licensee determined that, contrary to Technical Specification (TS) surveillance requirement 4.4.13.1 and Section XI of the ASME Code, the Unit 2 pressurizer vent valves 2-RC-105 and 106 were not tested following maintenance during the spring 1988 maintenance outage. At the time of discovery the plant was in operation, thus preventing testing of these valves. The licensee has since remained in TS Action Statement 3.4.13.b.1. This is a licensee identified violation (318/88-08-03).

No unacceptable conditions were noted.

7. Concerns Relative to Instrument and Controls Maintenance (93702) (RI-88-A-0044)

In response to concerns raised by a former Instrument and Controls (I&C) contractor employee the inspector and licensee identified the following information. On April 4, 1988 during the performance of surveillance test procedure STP M-529-1 (Revision 4 dated October 29, 1986) Section II G of the procedure incorrectly specified the locations of the leads to be lifted and later reterminated for the instrument loop for containment pressure transmitter 1-PT-5310. The procedure was changed to line out the error and fill in a different location and was then completed without first obtaining the necessary approvals for implementation of a temporary change per Calvert Cliffs Instruction CCI 101J, Section V. CCI 101J requires such changes, where no procedure intent changes are involved, to be approved by two members of plant management, at least one of whom holds a Senior Reactor Operators license on the unit affected, with a subsequent review by the Plant Operations and Safety Review Committee (POSRC) within 14 days. This is a violation (50-317/88-07-04). The inspector identified that the line entry change made by the technicians was incorrect. It specified lead locations as terminal board (TB) locations TB-A-108 for wire 4-MPG6 and TB-A-108 for wire A111. The licensee stated that the correct terminals were TB-A-108 and TB-A-109 respectively.

STP M-529-1 was subsequently performed again satisfactorily using correct terminal numbers.

The cause of the procedure inaccuracy was that Revision 4 of the procedure was pre-staged with the work package immediately prior to the outage. Shortly thereafter, the terminal locations were changed by a modification which installed a new plant computer, and Revision 5 was issued which modified the terminal locations.

After learning of the contractor's concern, the licensee removed pre-staged material which was subject to change from outage work packages to prevent other similar events.

The inspector pointed out to the licensee that the technicians involved in the April 4, 1988 test had also noted in the procedure that the computer point for 1-PT-5310 was X-816 instead of X-815, as noted in Revision 4. Revision 5 still lists X-815 and is probably incorrect. He reported this to the licensee for evaluation/correction.

Another concern raised to the NRC was that loop drawings do not match as-built drawings for the Control Room and remote shutdown panels and that terminal boards were not appropriately labeled. A specific example given was for Volume Control Tank (VCT) indications. The inspector learned that the VCT indication the contractor had worked with (and was probably therefore the subject of his concern) was VCT level indication. The inspector obtained the appropriate loop drawing and, with licensee technician assistance compared it to as-built conditions. He found that the terminal boards themselves can be easily located. Labeling of specific terminal numbers on the boards themselves is poor or missing. Some symbols on the boards may have meaning to engineers but are not familiar to technicians and therefore are not used. Some labels on wires are missing or difficult to read. Technicians, however, do not appear to be significantly hampered by these problems. They can count down to the proper terminal and can identify wires by other means such as examining "from" - "to" labels at other locations.

Emergency Operating Procedures purposefully minimize any dependencies on groups outside of operations to take expeditious actions such as installations of electrical jumpers or bypasses. Therefore time is usually available to identify leads. Certainly improved labeling would increase technician efficiency and would probably reduce probabilities of human error but it does not appear to currently prevent proper conduct of maintenance.

Loop drawings were developed relatively recently. They cover the safety related loops and some non-safety related. They represent a considerable improvement over the means formerly available to technicians wherein technicians had to use several prints and manually construct a loop circuit. Technicians stated that they have found the loop drawings to be accurate and very helpful. The inspector found that the VCT level indication loop drawing (1-LP-76 Sheet 63, Revision 0) in accompaniment with two outstanding design changes notices (DCN's) was accurate. The inspector did find that the computer data base used by technicians in determining the most current print and outstanding DCN's did not list sheet 63 and therefore technicians were unable by themselves to determine outstanding DCN's. Department procedures were not clear regarding what to do in this situation, but technicians correctly concluded that they must go to the print room to determine DCN status. The licensee has since committed to provide guidance to technicians (in procedures) on actions to take in this situation. According to technicians, the principle problems with prints currently concern unavailability of loop drawings for non-safety related loops and vendor prints that have not been updated to reflect as-built conditions. They feel they are in a much better situation with regard to prints than five years ago.

The inspector looked into one additional concern which was that contractor technicians hired by the licensee as well as licensee technicians and QC personnel were inexperienced in that QC personnel were not sufficiently qualified to inspect I&C work activities. The NRC has previously identified a problem with low experience levels in I&C technicians and a lack of personnel with I&C backgrounds in QC (Inspection Report 50-317/88-01, 50-318/88-01). Excluding Navy experience in the I&C area, the average level of I&C experience among the contractor I&C employees onsite was 3-1/2 - 4 years. ANSI/ANS 3.1-1978 specifies 3 years of working experience in their speciality (one year of which should be related technical training) for technician qualification. The experience levels of the contractors did not appear to be inadequate, especially considering that they were being used in helper roles and not as lead technicians.

The licensee will be asked to provide additional information relative to the concerns raised by the contractor employee. The NRC will assess that information and determine if additional corrective actions need to be taken.

8. Radiological Controls (71707)

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.

No unacceptable conditions were identified.

9. Observation of Physical Security (71707)

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 unacceptable conditions were noted.

10. Review of Licensee Event Reports (LERs) (90712 and 92700)

LERs 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 on site follow up. The following LER's were reviewed:

LER No.	Event Date	Report Date	Subject
Unit 1			
88-03*	12/09/86	05/22/88	Incorrect Steam Generator Tube Plugged Due to Personnel Error

Unit 2

88-03	03/17/88	04/16/88	Failure of a Steam Generator Isolation Check Valve
88-04*	04/27/88	05/20/88	Low Steam Generator Water Level Reactor Trip Due to #21 Steam Generator Feed Pump Trip

*Detailed examination of these events is documented in sections 3 and 12 of this inspection report.

No unacceptable conditions were noted.

11. Review of Periodic and Special Reports (90713)

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 of whether any information should be classified as an abnormal occurrence; and validity of reported information. The following periodic reports were reviewed:

-- March and April Operating Data Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated April 13 and May 11, 1988 respectively.

During this review the NRC inspector noted deficiencies in the license's reporting of the failures of and challenges to the pressurizer power operated relief valves (PORVs) and pressurizer safety valves.

On May 7, 1980 the NRC imposed upon all operating reactors five additional TMI-2 related requirements and requested that licensees reply within 30 days by stating their commitment to meeting these requirements and their associated schedules. One of these requirements, Item II.K.3, "Final Recommendations of B&O Task Force" consisted of 28 separate actions. One of these actions, II.K.3.3, "Reporting Safety and Relief Valve Failures and Challenges," required licensees to provide annual reports of safety valve and relief valve failures and challenges as of April 1, 1980. Licensees were required to implement this item by January 1, 1981. On June 18. 1980 the Baltimore Gas and Electric Company responded to the May 7, 1980 NRC letter, stating that they would not submit the Item II.K.3.3 annual report as current reporting requirements (i.e., 10 CFR 50.72, TS 6.9.1.8 and NUREG-0020) would render the Item II.K.3.3 annual report duplicative. Subsequently, the NRC issued NUREG-0737, "Clarification of TMI Action Plan Requirements," which incorporated all TMI-related items that were approved by the Commission for implementation. Pursuant to 10 CFR 50.54, "Conditions of Licenses," all licensees were requested to furnish within 45 days a confirmation of implementation dates for all Action Items or requests for relief from any Action Item with which the licensees did not intend to comply. Included was Action Item II.K.3.3 which required the reporting of safety valve and relief valve failures and challenges with submission of the first annual report by January 1, 1981 for the period from April 1 to December 31, 1980. In the licensee's December 15, 1980 response to NUREG-0737 and in all subsequent submittals, the licensee did not comment upon nor request relief from Action Item II.K.3.3. The Commission then issued a Confirmatory Order, dated July 10, 1981, which required the licensee to implement all TMI Action Items as provided therein. This included implementation of Action Item II.K.3.3, requiring submission of a report by January 1, 1981, for the period April 1 to December 31, 1980, documenting all PORV and safety valve failures and challenges; and requiring submission of said report annually, thereafter.

Subsequently, on March 9, 1982 the Commission issued amendments to the Calvert Cliffs Units 1 and 2 TS which incorporated the Action Item II.K.3.3 requirements into TS 6.9.1.4 and 6.9.1.5.c. These amended TS specify that a report shall be filed on an annual basis prior to March 1 of each year, including documentation of all failures and challenges to the pressurizer PORVs or safety valves which occurred during the previous year.

In 1987, after the NRC staff expressed concern over the licensee's compliance with the reporting requirements of TS 6.9.1.4 and 6.9.1.5.c, the licensee identified in its July 1, 1987 letter to the NRC that it had failed to submit these reports as required for the years of 1984 through 1986.

During the April 1988 review of these reports, the NRC inspector found that 1) the licensee apparently did not submit either the historical data of failures of and challenges to PORVs and safety valves for the period of April 1 to December 31, 1980 or the annual reports for the years 1981 and 1982 as required by the NRC Confirmatory Order dated July 10, 1981, 2) in addition to the licensee identified failures to report for 1984-1986, the licensee did not submit this annual report of failures and challenges to PORVs and pressurizer safety valves for the year 1987 in apparent noncompliance with the provisions of TS 6.9.1.4 and 6.9.1.5.c. Failure to submit the 1987 report was also contrary to the corrective action the licensee specified in its July 1, 1987 letter to the NRC. In that letter the licensee asserted that corrective actions for the previous failures to report were completed by assigning responsibility for this annual report to appropriate plant management. This event as a whole is indicative of a lack of adequate management attention regarding prompt response and compliance with NRC requirements (e.g., NUREG-0737, an NRC Confirmatory Order and Technical Specification reporting requirements) and constitutes an apparent violation (50-317/88-07-02; 50-318/88-08-02).

12. Licensee Self-Identification of Problems (93702)

Over the past several months the licensee has been increasingly proactive in identifying problems and potential safety concerns through their QA and QC organizations and through engineering and line organizations. This is a very positive effort.

In this inspection period the below described problems were licensee identified.

While performing eddy current testing on tubes in the #12 steam generator (SG), the plug which was supposed to be installed on the cold leg side for tube R94-L66 was missing. At the last outage, when the tube was supposed to have been plugged, that tube had a 44% through-wall indication. The technical specification plugging limit is 40%. That tube's hot leg side was properly plugged. The cold leg side plug was found to have been mistakenly installed in an adjacent tube (R93-L67). An eddy current exam of tube R94-66 showed 41% through-wall indication meaning the tube had not further degraded over the last operating cycle. The tube was then properly plugged. The error had apparently been made by the Combustion Engineering (CE) crew who performed the plugging operation last refueling outage. CE also had performed the QC function for the plugging. Normally Westinghouse (W) has done plugging for the licensee. In the current outage W performed the plugging and the licensee performed the QC function. This is a licensee identified violation (317/88-07-03).

On April 14, 1988, the licensee reported that they had identified a new possible failure mechanism for "air sets" (air regulators) which control air pressure to solenoid valves associated with control valve actuators. Several regulators in the plant contain non-metallic (e.g. BUNA-N) diaphragm material which can degrade due to adverse environmental conditions both in normal service but more likely in post-accident conditions. Failure of this material can allow pressure downstream of the regulator to increase to full instrument air system pressure. This pressure can exceed design conditions of some model solenoid valves and cause the solenoid valves and therefore also their associated control valves to reposition. This unwanted repositioning of valves has a potential for defeating safety functions. Additionally, full instrument air pressure downstream of the solenoids has the potential for causing control valve actuator damage/failure, control valve jamming/seat damage, or undesirable stroking times. The problem was limited to 20 valves on each unit. The licensee performed a case-by-case evaluation of the potential impact on the plant should the airset(s) fail under accident conditions. The licensee was able to conclude that by means of temporary compensatory actions, which were incorporated into procedures, required safety functions for these valves could be fulfilled. During the current Unit 1 outage the affected solenoid valves will be replaced with valves designed for full instrument air pressure. Additionally, relief valves are being installed downstream of the airsets and solenoids involved to prevent any possible damage to valve actuators if the airsets failed and allowed full instrument air pressure downstream. Similar corrective actions will be taken at the next Unit 2 outage of sufficient duration.

The airset concerns above grew out of a separate but related issue in which the licensee identified that failure of airsets (with BUNA-N) for charging system valves CV-517, 518 and 519 (loop charging isolation and auxiliary spray isolation) could render one of two long term core flush (to prevent boron precipitation in the core in longer term post accident conditions) paths. At one time the licensee had replaced the airsets for these valves with valves containing viton versus BUNA-N material. Through a configuration control breakdown (airsets are non-safety related) BUNA-N containing airsets were later installed back into the system. The licensee replaced the actuators for CV-517, 518 and 519 with actuators not requiring airsets during the current Unit 1 refueling outage. Similar replacements will be installed during the next Unit 2 refueling outage.

The LPSI pump coupling problem discussed in section 6 of this report was licensee identified through the vibration monitoring program.

A shallow surface indication on the casing of a reactor coolant pump was identified though the Inservice Inspection Program. That indication was easily ground out.

The yoke on one of the Unit 1 shutdown cooling suction valves (1-MOV-652) was found to have boric acid corrosion damage. That yoke was replaced during the refueling outage.

A potential issue with improper grease or mixing of greases in motor operated valves was identified and investigations to sample and determine if problems exist were begun. This will be discussed in the following inspection report.

13. Exit Interview (30703)

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.