U. S. NUCLEAR REGULATORY COMMISSION
Region I

Docket Nos.:	50-317 50-318	License Nos.:	DPR-53 DPR-69

Report Nos.: 50-317/89-04
50-318/89-04

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: February 21 - April 3, 1989

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Approved by: David T. Limroth 5/5/89
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Reactor Projects Section No. 3A

Summary: February 21 - April 3, 1989: Inspection Report Nos. 50-317/89-04 and 50-318/89-04

Areas Inspected: Facility activities, routine inspections, operational events, maintenance, surveillance, radiological controls, physical security, NRC notifications, process for temporary changes to plant equipment. Licensee Event Reports, reports to the NRC, and licensee action on previous inspection findings.

Results: Four violations were identified in the following areas: failure to implement and establish procedures (see Sections 3.B, 3.H, 3.I, and 4); failure to satisfy snubber surveillance requirements (see Section 5); failure to properly implement emergency plan and the fire protection program (see Section 3.A); and failure by POSRC to review operational events for potential safety hazards (see Sections 3.G, 3.J and 4).

Performance in the area of safety assessment has been inconsistent. It included weaknesses as demonstrated in the failure to identify the root causes of the leak in the steam generator blowdown line and a failure to demonstrate appropriate conservatism in the approach to resolution of this issue from a safety standpoint. It also included strengths exhibited during resolution of the events described in Sections 3.C, 3.E, and 3.F.

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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. Night shift inspections were conducted on March 1, 2, 7, and 31, 1989 and weekend inspections were performed on March 4, 12, 19, and April 1, 1989.

1. Summary of Facility Activities

Unit 1

The unit began the period at power. The unit went to hot standby on February 26 and 27, 1989, to repair a leaking third stage extraction line tap-off. The unit entered a mini-outage on March 2, 1989, to replace #11 Reactor Coolant Pump seal (with a new Bingham seal) and to correct control room deficiencies. On March 26, 1989, the plant heated up and paralleled to the grid on March 29, 1989. Later on the same day the unit was shut down due to high sulfates (see Section 3.j). The unit ended the period shut down due to a high concentration of sulfates in the reactor coolant system (RCS).

Unit 2

The unit began the period at power. On February 23, 1989, power was reduced to 92% due to fish influx which required stopping #22 Circulating Water Pump on high travelling differential pressure. The unit was returned to power on the same day. A fire in the control room handswitch for the #22 auxiliary feedwater pump's throttle/trip valve occurred on March 1, 1989 (see Section 3.a).

On March 7, 1989, power was reduced to recover from a partial loss of condenser vacuum (see Section 3.b). That same day, the unit was shut down to repair #22 Feedwater Regulating Valve (see section 3.c). The unit returned to power on March 9, 1989. On March 17, 1989, the unit was shut down due to an increasing leak on #22 steam generator blowdown piping (see Section 3.g). The unit entered the refueling outage on March 24, 1989, and ended the period shut down for a planned 65-day refueling outage.

General

On February 22, 1989, U.S. Representative Thomas McMillen visited the site to tour the facility and meet with the resident inspectors. An NRC Special Team Inspection was conducted at the site during the weeks of February 27, March 6, and March 29, 1989.

During the week of February 27, 1989, Region I personnel inspected in the area of Environmental Qualification.

On March 3, 1989, the licensee and NRC held a public meeting at the facility to discuss the results of the Systematic Assessment of Licensee Performance.

During the week of March 27, 1989, the Institute of Nuclear Power Operations (INPO) conducted a Special Assist visit in the areas of Significant Operating Event Reports and Human Performance Evaluation System.

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.

No unacceptable conditions were noted.

b. System Alignment Inspection

Operating confirmation was made of selected piping system trains. Accessible valve positions and status were examined. Visual inspection of major components was performed. Operability of instruments essential to system performance was assessed. The following systems were checked during plant tours and control room panel status observations:

-- Unit 1 Chemical Volume Control System

-- Unit 1 High Pressure Safety Injection

-- Unit 1 Low Pressure Safety Injection

-- Unit 2 Service Water System

-- Unit 2 No. 12 Emergency Diesel Generator Air Start System

No unacceptable conditions were noted.

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. Plant housekeeping and cleanliness were evaluated.

No unacceptable conditions were noted.

3. Operational Events (93702)

a. Fire in a Unit 2 Auxiliary Feedwater Pump Trip Circuitry

On March 1, 1989, with Unit 2 operating at 100% of rated power, a fire under the bench board section of control room panel 2C04 occurred at 4:47 p.m. The fire involved the burning of the handswitch (2-MS-3988-HS) for the #22 steam driven auxiliary feedwater (AFW) pump's throttle/trip valve (2-MS-3988). At approximately the same time a turbine building operator reported that the solenoid (2-MS-3988-SV) for the throttle/trip valve was also smoking and appeared to have overheated. The duration of the fire in the handswitch lasted between one and two minutes. A portable halon fire extinguisher was used twice by a control room operator to extinguish the fire. At the time of this event the No. 22 AFW pump was out of service for the repair of a faulty trip reset mechanism and the handswitch was being used to verify proper movement of the valve as part of post maintenance testing. NRC review of the licensee's maintenance activities on the subject valve and maintenance actions to recover from the event are contained in Section 4 of this report.

As a result of the fire, minor damage to wiring adjacent to the handswitch was noted. This wiring is associated with the steam inlet pressure indicators (2-PI-3987 and 2-PI-3989) for the #21 and #22 AFW pumps. Operability testing of electrical components located on the 2C04 panel and temporary repairs to the affected wiring were completed at 9:25 p.m. and 11:45 p.m., respectively. An informational ENS call was made at 5:34 p.m.

Because this event was viewed by the licensee as being significant, the Manager-Calvert Cliffs Nuclear Power Plant Department (CCNPPD) established a Significant Incident Finding Team (SIFT) on March 2, 1989, to determine the root cause(s), initiate corrective action, and make recommendations to prevent recurrence. The results of the SIFT's investigation, conclusions, and recommendations were submitted and reviewed at Plant Operations Safety Review Committee (POSRC) Meeting No. 89-52 on March 24, 1989. This resulted in the issuance of Calvert Cliffs Event Report 89-01 on March 29, 1989. The inspector noted that this report reflected positively on the detailed and thorough investigation and resulted in the development of appropriate recommendations that were generally introspective and self-critical of the licensee's performance.

The licensee's investigation revealed that during reinstallation of the actuator, insufficient clearance was provided in the overspeed trip linkage. This allowed the remote trip function of the valve to actuate by energization of the trip solenoid but, prevented actuation of a shunt mechanism that inserts a larger resistance coil in the circuit. By failing to actuate the shunt device, full closing current of about 30 amperes remained on the circuit instead of the normal 0.25 ampere holding current. Under this condition, momentary use of the control room handswitch resulted in welding closed the switch contacts. Since the handswitch is only rated for 2.5 ampere service, and the 10 ampere fuse in the circuit is sized to protect the circuit wiring, the overload condition resulted in the fire in the handswitch. Once the fuse blew the circuit over load was interrupted. The proper actuation of the shunt device is the function in the circuit intended to prevent an over load condition during the remote closing of the valve. The inspector identified no design inadequacies during the review of the control circuit for the AFW pumps throttle trip valve. However, the licensee has issued Field Change Request (FCR) 89-0035 to re-evaluate the existing design and improve the design of the remote trip function.

The inspector had the following additional comments pertaining to the licensee's performance in response to this event:

-- Directly following the event, the operations department responded well by demonstrating an appropriate level of concern for the potentially negative impact that the control room panel fire could have had on adjacent control circuits. However, the testing program used an extensively altered procedure STP-0-9-2, Auxiliary Feedwater Actuation System, Monthly Logic Test. NRC concerns pertaining to the licensee's inappropriate control of procedure changes will be documented in the report of the Special Team Inspection (50-317/318: 89-200). All control circuits and associated equipment were subsequently verified to be operable.

-- The immediate response of the control room personnel included the use of a portable fire extinguisher twice to contain and extinguish the fire; telephone paging three times the fire and safety technician, who functions as the fire brigade leader; and calling for an electrician to come to the control room. Because the fire was out quickly, the emergency alarm was not sounded and the fire brigade was not assembled. It appeared that at the time this decision was made the control room personnel were neither aware of the conditions that caused the fire, nor considered the possibility that what appeared to be a controlled situation could degrade.

Calvert Cliffs Instruction (CCI) 133 I, Calvert Cliffs Fire Protection Plan, requires in Section VII that the control room operator sound the emergency alarm and announce the location of the fire over the public address system. Additionally, Emergency Response Plant Implementing Procedure (ERPIP) 3.0, Revision 13, Immediate Actions, requires the control room to notify on site personnel of a reported fire by sounding the emergency public address alarm, announcing the location of the fire and notifying the Fire Brigade Leader by radio pager. Technical Specification (TS) 6.8.1.e and f, respectively specify, in part, that written procedures shall be implemented for Emergency Plan and Fire Protection Programs. The failure of control room personnel to implement the requirements of the above enumerated procedures during the fire in the control room panel is a violation (50-318/89-04-01).

b. Partial Loss of Condenser Vacuum, Unit 2

On March 7, 1989, at 1:28 a.m., the unit was operating at 100% power. The Unit 2 Turbine Building Operator (TBO) was performing a condenser air in-leakage check per Operating Instruction (OI)-13, Part IV, Condenser Air In-Leakage Check. The TBO skipped a step in the procedure which resulted in a valve lineup which provided a path from atmosphere to the condenser. Vacuum rapidly decreased causing control room low vacuum alarms. Control room operators responded to the alarm condition by reducing power and the TBO corrected the valve lineup and caught the decreasing vacuum at 22.5 inches high. The automatic turbine trip occurs at 20 +/- 2 inches high.

The condenser air removal units use an air ejector in combination with a mechanical vacuum pump to maintain condenser vacuum. The ejector utilizes air from atmosphere via a three-way valve. When performing the air in-leakage test, the three-way valve is positioned so that outside air is isolated. Thus, by isolating the discharge header isolation valve to the plant vent, the only air being forced through a flowmeter used to measure in-leakage by the vacuum pump would be in-leakage. The flowmeter line is capable of handling relatively small air flow rates. When the three-way valve was not positioned in accordance with the procedure, the capacity of the flowmeter tubing was exceeded and air backed into the condenser thereby reducing vacuum.

The control room operator began inserting control rods to reduce power in accordance with Abnormal Operating Procedure (AOP)-7G, Partial Loss of Condenser Vacuum. The TBO observed the flowmeter indication was pegged high and opened tne plant vent header isolation valve in accordance with OI-13. Vacuum decrease stopped. Other plant personnel responding to page announcements found the three-way valve mispositioned and repositioned the valve. Vacuum began to increase slowly. Vacuum returned to normal approximately ten minutes after event began. Power was decreased to 96% power and returned to 100% shortly thereafter.

AOP-7G requires a turbine trip when condenser vacuum is less than 24.5 inches high for more than about one minute. The licensee states the operator did not trip the unit because the improper lineup had been identified and corrected about the same time the control room operator identified the trip criteria. The licensee contacted the turbine vendor to determine the effect of operating the turbine in the low vacuum environment. The turbine vendor indicated no damage would occur.

Corrective actions that were under consideration or implemented at the close of the inspection period included (1) review of the factors leading to the procedure non-adherence with operations personnel (completed); (2) label the position on the three-way valve; (3) consider reducing the frequency of the condenser air in-leakage check from daily to weekly; (4) install a sign on header isolation valve to plant vent warning that valve position is trip sensitive; (5) relocate flowmeter indication so it is visible from header isolation valve positioner; and (6) correct in-plant communication problems. Timely operator action avoided potential safety system challenge.

TS 6.8.1.a and Reg. Guide 1.33, Appendix A requires that the procedures for power operation be implemented. Tne failure to follow OI-13 is considered an example of a violation of TS 6.8.1.a requirements (317/89-04-01; 318/88-04-02).

c. Unit 2 Shutdown Due to No. 22 Steam Generator Main Feedwater Regulating Valve Positioner Failure

On March 7, 1989, at 8:00 a.m., with Unit 2 operating at 100% power, control room personnel contacted the secondary system engineering group and informed them of increases in the perturbations in the unit's feed system. The unit had been experiencing some minor feed system perturbations. Investigation revealed that the perturbations were related to the Feedwater Regulating Valves (FRV) controls. Additionally, it was determined that further investigation would require a shutdown. Shortly thereafter, steam generator (SG) level oscillations increased to approximately +/- 5 inch deviation from the 0 inch reference value. Control room personnel dispatched plant personnel to investigate the oscillations and while the investigation was in progress at approximately 11:40 a.m., #22 SG level began to decrease at an unexpected rate. At 11:45 a.m., AOP 3G was entered and control room personnel recovered level using manual feedwater system control. The #22 SG level had decreased to - 31 inches prior to returning to the normal value of 0 inches. During the event, all reactor protection system (RPS) low SG level pre-trip alarms were received; no RPS or engineering safety features actuation system (ESFAS) setpoints were reached.

Plant watch personnel discovered that air was blowing from #22 SG FRV positioner. It was decided to place #22 FRV in manual control for troubleshooting and/or repairs, in accordance with O) 12A, Feedwater System. With the #22 FRV in manual control, the plant entered TS 3.0.3, at 12:20 p.m., based on not meeting TS Limiting Condition for Operation (LCO) 3.3.2.1, ESFAS response time for #22 SG FRV.

Troubleshooting of #22 SG FRV positioner indicated that a gasket failure was the cause of the air leakage. Repairs were completed and the plant exited the TS Action Statement 3.0.3 at 2:20 p.m.

Shortly thereafter, the POSRC met and concluded that post maintenance testing of #22 SG FRV was required to verify TS Surveillance Requirement 4.3.2.1.3, Engineering Safety Features Response Time, Table 3.3-5.8(a), feedwater flow reduction to 5% on a reactor trip. A unit shutdown was initiated at 4:00 p.m. and TS 3.0.3 was reentered for not meeting TS LCO 3.3.2.1. At 4:55 p.m., utilizing the ERPIP, an Unusual Event was declared and ENS notification was made. At 6:57 p.m., Mode 2 was entered and Mode 3 was entered at 7:10 p.m.

Following the reactor shutdown, Surveillance Test Procedure (STP) M-521-2, ESFAS Time Response Test, was performed satisfactorily on #22 SG FRV to obtain as found data. Following adjustment to the air pressure reading, STP M-521-2 was again performed satisfactorily and at 11:30 p.m., the unit exited TS 3.0.3 and the Unusual Event.

The licensee determined that the cause of failure of #22 FRV positioner was failure to perform adequate preventive maintenance. The air leak was caused by a gasket which was in a brittle and degraded condition. Present work practices do not provide for review, overhaul and replacing of gaskets on secondary system components. A similar event which resulted in a unit trip is discussed in Inspection Report 50-317/88-19; 50-318/88-19.

The licensee is considering the following recommendations in order to avoid future recurrence: (1) Establish Reliability Centered Maintenance (RCM) for the Feedwater Regulating Valve actuators and positioners to determine the best preventive maintenance course. (2) Establish a list of and perform a review of all vital secondary components in a harsh environment to determine if adequate preventive maintenance is performed.

Throughout this event, the inspectors observed and noted that the licensee's decisions and performance exhibited the proper safety perspective and conservatism.

d. Loss of Operability of #11 and #12 Salt Water Air Compressors Due to Failure of Instrument Air System Check Valve 1-IA-650

On March 14, 1989, at 9:00 p.m., Unit 1 was in Mode 5. An instrument air boundary check valve (IA-650) failed a back leakage test. Subsequently, the check valve was replaced and two manual isolation valves were installed to allow for header isolation in addition to facilitating future replacement of any leaking check valve. The new check valve was tested several times and failed. The licensee's design engineering group determined that loss of the valve due to its location would jeopardize both salt water air compressors (SWAC) and, therefore, both trains of the salt water system. This determination was made at 1:30 p.m. on March 24, 1989, and an ENS notification was made at 2:50 p.m.

The testing, which resulted in the identification of the failed valve on March 14, 1989, was triggered by a partial loss of instrument air (IA) which occurred in Unit 1 on December 20, 1988 (see Inspection Report 317/88-32). The significance of the December partial loss of IA was that once the source of that bleed down of IA was located and isolated, the SWACs should have had the capacity to supply the feedwater regulating valve (FRV) and prevented the feedwater transient which occurred. As mentioned above, on March 17, 1989, the old check valve (IA-650) was replaced with a new check valve and two manual isolation valves. Further test showed some improvement in the leak rate, however, the licensee decided to isolate IA-650 and has placed an order for a soft seat type check valve. Essential load to the containment is supplied via an alternate path. On March 25, 1989, the licensee tested the salt water IA system in the new configuration, including check valve IA-730 which became the new boundary valve between safety related and non-safety related, and the results were satisfactory.

The SWACs were added to the IA system in July 1974. Originally, it was determined that during every mode of operation and event except Loss of Coolant Accident (LOCA) before recirculation, the salt water system would have to be throttled. The throttling requirements resulted from the potential run out of the salt water pumps. Therefore, the discharge valves on the component cooling and service water heat exchangers were modified to allow the valves to be supplied alternately from the SWACs during a LOCA.

Upon receipt of safety injection actuation signal (SIAS), the SWACs start automatically to provide backup air to the aforementioned heat exchanger discharge control valves. Normally IA is secured after a SIAS and is restored once service water is restored to the turbine building and SIAS is reset.

IA system essential and non-essential loads are separated by boundary check valves except for containment loads which are separated by an air pressure switch actuated air-controlled isolation valve. Once the SIAS signal is received, the SWACs supply air only to essential loads upon IA header pressure decreasing to the point where the boundary check valves seat. Hence, the loss of one of the boundary check valves could result in total loss of IA due to the capacity of the SWACs. The licensee has identified that with the worst case scenario of a LOCA with concurrent loss of off site power, the salt water air system would be rendered inoperable when considering the excessive back leakage through boundary check valve IA-650. This would result from not having a constant air source in order to throttle the salt water heat exchangers discharge control valves. The lack of air to throttle the discharge control valves would result in run out of the salt water pumps and eventual loss of the component cooling water systems and the service water system. The postulated event was considered reportable.

The following corrective actions have been implemented or are under consideration: (1) Install manual isolation valves on either side of IA-650 to allow for its isolation. (2) An additional pathway for IA compressors supplying air to containment essential loads was established through IA piping to the auxiliary feedwater components normally isolated. The configuration of the salt water air system was verified to be safe by safety analysis and POSRC. (3) A new soft seat check valve is being reviewed to replace the existing one. (4) Unit 1 boundary check valves that were not tested will be tested in accordance with the overall effort to respond to NRC Generic Letter 88-14 "Instrument Air Supply Problem Affecting Safety-Related Equipment." (5) The Unit 2 IA system will be tested to identify any similar problems.

No unacceptable conditions pertaining to the licensee's response to this event were noted.

e. Nuclear Fuel - Potential Loss of Shutdown Margin

In May 1988, the licensee received NRC Information Notice 88-21. This notice alerted licensees to undesirable procedural practices that could lead to inadvertent criticality events. Based upon their initial review, the licensee requested information from their fuel supplier, Combustion Engineering in November 1988. At that time, the licensee was developing concerns that the increasing enrichment of fuel over the last several fuel cycles, with some of the fresh fuel assemblies being highly reactive under refueling conditions, in conjunction with their refueling procedures allowing replacement of fuel assemblies in intermittent positions during core alterations, could challenge the required five percent shutdown margin. In the extreme, the licensee was concerned that such conditions could allow an inadvertent criticality to occur.

On March 10 and 15 respectively, the licensee provided telephone notification and written follow up for their determination that the potential loss of shutdown margin meets the criteria of a defect on a basic component as defined in 10 CFR 21. Combustion Engineering issued Information Bulletin No. 89-01 on March 14, 1989, describing the potential concerns identified by the licensee. The licensee has informed the inspector that procedure FH-6, Core Refueling Procedure, will be revised.

When questioned by the inspector as to why this event was not reportable under 10 CFR 50.72 and 50.73, the licensee's representatives indicated that it was their judgment that since (1) the probability of forming potentially critical configurations or reduced shutdown margin configurations as a result of interim fuel moves was extremely small and (2) that interim fuel moves had not been identified to have been used during recent Unit 2 refueling cycles, the condition was not reportable.

The manner in which the licensee performed operational assessment feedback evaluation of NRC Information Notice 88-21 demonstrated good performance in resolving this technical issue from a safety standpoint. The inspector had no further questions of the licensee on this item.

f. Identification of Damaged Seismic Restraint on #11 and #12 Low Pressure Safety Injection Common Suction Header and Subsequent Water Hammer

On March 17, 1989, at approximately 12:30 p.m. with Unit 1 shut down in Mode 5, a licensee system engineer observed that a vertical support on the Low Pressure Safety Injection (LPSI) System suction piping was bent. The system engineer notified design engineering, quality control and operations. Further, the licensee contacted Bechtel to obtain their assistance in determining the amount of force required to distort the support. Bechtel determined that approximately 5,300 pounds of force would have been required. The licensee's design engineering group designed a new replacement pipe restraint. Bechtel reviewed and confirmed that with the new design, the stresses on the LPSI suction piping would not be exceeded. The licensee determined the most likely cause of the vent was #11 LPSI pump discharge check valve slamming shut when the pump was tripped generating the force to bend the restraint.

POSRC approved the new design restraint on March 18, 1989. The installed restraints were removed on March 19, 1989. During the removal process, there was an inadvertent SIAS actuation. LPSI system suction piping was observed to move approximately 1/16th of an inch. Operators secured the SIAS actuation and when #11 LPSI pump was stopped, the pump's discharge check valve slammed shut. The LPSI suction piping was observed by workers in the room to move a total of approximately 1 inch in the east-west direction. The licensee evaluated the evidence confirming that the slamming check valve could have caused the damage. They concluded that the damage to the restraint occurred when the check valve slammed shut following #11 LPSI pump trip causing the resulting force in the direction toward the pump and suction piping.

The licensee installed the new design restraint on March 19, 1989. The following corrective actions were performed by the licensee prior to declaring the LSPI system operable:

(1) The inservice inspection (ISI) group performed a walkdown of Unit 1 high pressure injection system, containment spray system and component cooling water system to inspect for damage. No significant damages were found.

(2) The discharge check valves on #11 and #12 LPSI pumps were tested for back leakage and found acceptable.

(3) The #11 LPSI pump was checked for excessive vibration caused by possible misalignment due to the event. No problems were found.

(4) The piping supports were reinspected after the SIAS event. No problems were found.

(5) The ISI group inspected the LPSI discharge and suction piping up to the first hanger and found no problems.

(6) The ISI group performed NDE testing on five suction piping welds and on the pump suction nozzle weld and found no problems.

The POSRC declared the system operable following completion of the aforementioned items.

The licensee's On-site Safety Review Committee and interfacing groups displayed proper safety perspective throughout this event including the solutions and conclusions. The NRC considers this proper functioning of the committee and proper utilization of available technical resources.

g. Unit 2 Shutdown Due to No. 22 Steam Generator Blowdown Line Leak

On March 7, 1989, Unit 2 was operating at 100% power. The unit was shut down at approximately 7:00 p.m. to repair #22 FRV (see Section 3.c).

During the shutdown, a routine containment walkdown identified a leak on the #22 SG bottom blowdown line near the 10 foot elevation. The leak was identified as geometrically round and characterized as a pin hole located on the vertical run of pipe. Concurrent with the discovery of the blowdown line leak, a heavy rust area was discovered in Unit 2 salt water system in the service water room. Later in the evening of March 8, 1989, it was concluded that there was not a through wall failure in the salt water system since the pipe wall satisfied thickness minimum wall requirements.

Based on recommendations from the system engineer, material engineering group and design engineering group, the licensee elected to take the unit to power on March 9, 1989. The licensee's decision to continue to operate with an unisolated leak in the blowdown line was based on the following (1) examination showed that the blowdown pipe leak was a localized pin hole which was not likely to propagate within the following two weeks (two weeks was the time to the licensee's refueling outage); (2) the leak was characterized to have been next to and associated with the weld start/stop point where excess reinforcement weld material was present; (3) the leak rate was small (estimated 2 gallons/hour); (4) the leak would be monitored using the containment sump which was drained after each accumulation of approximately 44 gallons; (5) the unit would enter the refueling outage in two weeks, thereby allowing for the expeditious repair of the line; and (6) catastrophic failure, although considered unlikely, was bounded by Chapter 14 Feedwater Line Break Analysis. In addition, the licensee based their position on ASME XI, IWA 5250 which they believed allowed sources of leakages to be evaluated by the licensee for corrective action.

On March 9, 1989, Unit 2 was at 30% power holding for chemistry. The licensee held a conference call with NRC Region I (NRC:RI) and NRC Office of Nuclear Reactor Regulation (NRC:NRR) which resulted in the following agreements: (1) The licensee would question their Authorized Nuclear Inspector and determine whether he agreed with the licensee's interpretation of the ASME code. (2) The licensee would solicit a code interpretation to clarify vagueness of the code relative to leaks on Class 2 piping. A subsequent conference call on March 10, 1989, among the aforementioned groups conveyed the additional NRC position that a relief request from ASME Code Section XI was needed from the licensee. The licensee volunteered that should the sump drain interval reach once every eight hours, an entry into the containment would be made along with a re-evaluation. Further, if the sump drain interval reached once very 4 hours, the unit would be shut down.

On March 15, the unit had been operating at or near 100% power since March 10. A conference call was held between the licensee, NRC:RI and NRC:NRR to discuss the increases in containment sump drain interval and to further discuss the licensee's course of action. The licensee again volunteered to shut down should containment sump interval reach every 4 hours. During this conference call, the licensee indicated that the pin hole defect was, in fact, in the base metal in an active section of the blow down line. The NRC was previously informed that the pin hole leak was in the weld material and that the relatively large pressure drop was being absorbed by the tortuous path provided by the fillet weld. On March 16, 1989, the licensee made an entry into the containment and presented their findings to POSRC. Subsequently, another conference call between the licensee, NRC:RI and NRC:NRR was held to discuss the status of the leak. A decision was made by the NRC to deny the code relief request effective 12:00 p.m. on March 17. The inspector was notified at 2:00 a.m. on March 17 that the sump drain interval had reached less than once every 4 hours and a shut down of the unit had commenced. The licensee requested code relief to hold in Mode 3 for testing. The request was denied and the licensee entered Mode 5 at approximately 1:30 a.m. on March 18, 1989.

The inspectors observed the above events and reached the following conclusions:

(1) The Chairman of the POSRC failed to exercise his duty by not utilizing a significant technical resource consistent with the Technical Specifications 6.5.1.6.g which specified the responsibilities of the POSRC for "Review of facility operations to detect potential safety hazards".

(2) The licensee failed to recognize the potential for challenging safety systems and entered into power operations without fully recognizing a reduced safety margin.

(3) Significant emphasis was placed on the weld defect aspects of the problem while the potential contribution made by cavitation/erosion/corrosion was de-emphasized or ignored.

(4) Solutions were structured to provide justification for continued operation without the proper safety perspective.

The failure of the POSRC to review the through wall leak on the #22 SG blow down line for detection of potential safety hazards prior to the return of Unit 2 to power on March 9, 1989, constitutes one example of a violation of the TS requirement 6.5.1.6(g) (317/89-04-0[illegible], 318/89-04-03).

h. Inadvertent Engineered Safety Feature Actuation with Injection-Unit 1

On March 19, 1989, at 2:30 p.m., with Unit 1 in Mode 5, operating personnel caused an inadvertent SIAS signal, which is part of the engineered safety features of the plant, during the performance of Surveillance Test Procedure (STP) 0-7-1, Engineered Safety Features Monthly Logic Test.

The unit was in Mode 5, pressurizer pressure was 250 psia and reactor coolant temperature was 130 degrees F. In order to allow plant operations with pressurizer pressures below 1740 psia, which is one of the SIAS setpoints, the SIAS signal can be blocked when pressurizer pressure is below 1785 psia. However, should pressurizer pressure increase above 1785 psia, SIAS will automatically be unblocked.

Since the test was being conducted below 1740 psia, the SIAS block function had to be removed to allow for system testing. Attachment I of the STP accomplishes both the removal and reinstating of the SIAS pressurizer pressure blocking function. That portion of the test that demonstrated the operability of the trip circuits in the unblocked conditions was completed satisfactorily. During the process of reinstating the SIAS pressurizer pressure blocking function, the reactor operator (RO) in the cable spreading room who was performing the test failed to request and verify from the control room operator the procedural requirements of STP 0-7-1, Attachment 1, to reinstate the block.

As a result of the missed step, a SIAS was initiated. The RO returned to the previous step by returning the actuation pots to a minimum. The control room had initiated EOP 8 (Functional Recovery Procedure), Attachment 2 (SIAS Verification Checklist) to verify that all systems had responded as expected and was so noted. The SIAS was blocked and all systems were returned to normal with the exception of the three emergency diesel generators which continued to run loaded as required, for one hour. The SIAS actuation pots were returned to their recorded setpoints.

The licensee will be reporting this event in an LER. The RO's failure to follow STP 0-7-1 constitutes a violation of TS 6.8.1.a which requires the implementation of procedures for conduct of TS surveillances (317/89-04-01; 318/89-04-02).

I. Inadvertent Partial Engineered Safety Feature Actuation without Injection - Unit 1

On March 20, 1989, at 1:20 p.m. with Unit 1 in Mode 5, operations personnel were restoring ESFAS Logic Cabinet "B" to service as per procedure OI 34, Section IX, Returning Actuation Logic Cabinets to Operation. There were two operations personnel involved, one RO who was performing the steps in the procedure and a Senior Reactor Operator (SRO) who was observing. The RO had completed the performance of step 25 of the procedure and requested that the SRO call the control room to confirm the Steam Generator Isolation Block in alarm condition. The RO returned to the procedure and performed steps 28 and 29. After completing step 29, the RO became aware he had skipped steps 26 and 27 of the procedure. The RO and SRO called the control room and conferred as to the best solution. It was collectively decided to back out of the procedure (i.e., undo steps 29 and 28). The RO then proceeded to do steps 26 through 29. The control room informed them of a partial actuation of the ESFAS "B" logic. The #12 boric acid pump started, #12 component cooling pump started and high pressure safety injection (HPSI) motor operated valves (MOVs) 1-SI-616, 626, 636, 646 opened. The pumps were stopped and the HPSI MOVs were shut after consulting the safety injection actuation checklist. ESFAS Logic Cabinet "B" was restored to service per OI-34. An ENS notification was made on March 20, 1989, at 2:20 p.m. The failure of operating personnel to follow procedure OI-34 which resulted in a partial actuation of ESFAS is an another example of violation (317/89-04-01; 318/89-04-02).

On March 8, 1989, the licensee issued General Supervisor of Nuclear Operations (GSNO) Standing Instruction 89-2, Supervision of Operation Activities, which indicated their elevated concerns with errors during major evolutions of the plant. The GSNO Standing Instruction required a Senior Licensed Operator (SRO) to directly supervise the performance of certain evolutions including ESFAS startup, shut down, and operations testing. On March 12, 1989, the GSNO Standing Instructions were further clarified to require the SRO; (1) to perform no hands on operation; (2) must have a copy of the procedure being used by the operator he is supervising; (3) must acknowledge the completion of each step of the procedure and give his OK before the operator is allowed to perform subsequent steps; and (4) review discrete blocks of the procedure prior to each major step. The aforementioned enhancements to operations that were established by the licensee to help ensure proper attention to detail and procedural compliance by operations department personnel appears to have been ineffective to preclude the full and partial ESFs that occurred on March 19 and 20, 1989, respectively. The licensee's inability to ensure procedural adherence is a continuing weakness that is of significant concern to the NRC.

j. Unit 1 Shutdown Due to High Sulfate Concentrations in the Reactor Coolant System

At 12:25 a.m. on March 29, 1989, the Unit 1 generator was paralleled to the grid following a maintenance outage that started on March 2, 1989. Plant heat up had started on March 26, 1989. Because of concerns expressed by the chemistry department that a potential release of chemical volume control system (CVCS) ion exchange (IX) resins into the reactor coolant system (RCS) might have occurred, further increase in power level above 60% of rated power was stopped at 12:50 p.m. until the issue could be resolved. At 7:00 p.m., the Manager-CCNPPD instructed the plant operators to commence a shutdown of the unit to Mode 5. The inspector was informed by the Manager-CCNPPD of their actions, which resulted from the high sulfate concentrations found in the RCS.

Based upon recent RCS chemistry sample analysis and reduced radiation field measurements outside the #12 CVCS IX unit, the General Supervisor-Chemistry (GSC) believed that a significant intrusion of ion exchange resin into the RCS had occurred. The most significant concern to the licensee was that a sulfate species, thiosulfate, had been identified on March 29, 1989, along with the current sulfate (S04) levels of approximately 200 ppb. The chemistry department uses ion chromatography as the method to measure sulfate, which produced an unknown or "ghost" peak. Because they were concerned about the possibility of reduced sulfate compounds, sodium thiosulfate was added to the sample, which produced a similar ghost peak and led to the tentative identification of thiosulfate. A review of licensee chemistry analysis reports indicated that on March 17, 1989, the sulfate level in the RCS was 97.2 ppb. Between March 20 and 24, 1989, the levels ranged between 1866 and 1272 ppb.

At the Plant Operations and Safety Review Committee (POSRC) meeting (No. 89-52) held on March 24, 1989, the GSC reported that a high sulfate condition (1.9 ppm) existed in the Unit 1 shutdown cooling system. The GSC related that the TMI-1 experience with high sulfur in the RCS resulted in significant steam generator tube degradation. The POSRC was told by the GSC that a possible source of the sulfate contamination might be charging pump packing. The GSC also indicated that the existing primary to secondary leak on Unit 1 might be the result of sulfur attack in the primary side of the steam generator tubes instead of the normal secondary side tube degradation. At 6:00 p.m. on March 29, 1989, the current status of the sulfate levels in the Unit 1 RCS was discussed at POSRC meeting No. 89-57. Because thiosulfate was identified, and known to be an identified aggressive corrosion species on steam generator alloy 600 tubes, and since the total amount of sulfur was unknown and there was high probability of it plating out in the system, the GSC recommended Unit 1 be shut down and a clean up of the RCS initiated. Consideration was given to the addition of hydrogen peroxide to oxidize all the sulfur species to sulfate. The GSC had held discussions with EPRI, Combustion Engineering, and a consulting firm NWT, who considered the GSC's recommendations to shut down the plant and perform clean up activities to be prudent.

On March 30, 1989, a SIFT was formed by the licensee to investigate the cause of high sulfate concentrations in the Unit 1 RCS, determine corrective actions required to return RCS to normal chemistry conditions, and complete an effects analysis. At of the close of the inspection period, their investigation was in process and will continue to be reviewed by the NRC.

The inspector reviewed the licensee's chemistry procedure CP-20 , Revision 1, Specifications and Surveillance of the RCS, which contains normal and action level values for sulfates. The last RCS chemistry results for sulfates prior to the heat up from Mode 5 on March 26, 1989 was on March 24, 1989. This value was 1272 ppb. No chemistry analysis was performed on March 25 and 26, 1989, however, a heat up from Mode 5 was initiated. CP-204, Table 1B, specifies that the normal value for sulfate in Modes 5 and 6 is less than 20 ppb. Table 1A of this procedure also uses this value for the Modes 1-4 normal range but, indicates that at a value of greater than 100 ppb an investigation into the cause and initiation of corrective action should occur. Although this procedure does not explicitly prohibit a start up under the RCS chemistry conditions that existed on March 26, 1989, it appears that less than fully effective management oversight was evident on the part of the chemistry department in its application of this procedure. Additionally, TS 6.5.1.6.g requires the POSRC to review facility operations to detect potential safety hazards. The licensee's plant start up on March 26, 1989, without a review by the POSRC of the existence and affects of high concentrations of sulfate in the RCS to detect potential safety hazards is considered an additional example of a violation of TS 6.5.1.6.g requirement (317/89-04-02; 318/89-04-03).

4. Plant Maintenance (62703)

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.

Unit 2 #22 Containment Spray Pump Bearing Failure

On March 2, 1989, during a routine review of the licensee's Non-Conformance Reports the inspectors discovered that #22 containment spray pump (CSP) had experienced complete bearing failure on June 3, 1987. Further inquiry indicated there had been little or no root cause analysis, inadequate documentation and no Plant Operating Safety Review Committee (POSRC) review.

The original NCR #7137 did not adequately document the investigation conducted by the system engineer at the time of closure which was in excess of one year after the event.

The event occurred on June 3, 1987, with Unit 2 in Mode 5. Operations started #22 CSP at 2:00 a.m. to fill the safety injection tanks. At 2:55 a.m., operations secured #22 CSP due to a smoking bearing. The bearing was hot enough to blister the paint on the pump. The original NCR mentioned a smoke alarm being received. No confirmation was found in either the operations logs or in fire protection records. Maintenance Order (MO) #207-154-052A was issued to repair the pump. Inspection of the pump indicated significant discoloration of the housing shaft and bearings which is indicative of overheating. The shaft had more discoloration than the thrust bearing. The thrust bearing showed more damage than the other bearings and would not rotate. There was burnt oil residue throughout the bearing housing. The MO documented gross misalignment such that the coupling could not be removed without pump disassembly. The licensee believes that the gross misalignment was the cause of the bearing failure. However, in the NCR closure, the licensee states the reason to be "low oil level". All parts resulting from this failure including the burnt oil sample have been misplaced or lost. Extensive search for the lost parts and oil sample have been fruitless.

A review of Nuclear Plant Reliability Data System (NPRDS) query report and in-house maintenance orders indicate this failure to be one-of-a-kind.

The licensee will be issuing an NCR to document the root cause analysis of #22 CSP failure. In addition, the following corrective actions will be or have been taken: (1) Continue monitoring oil reservoir level on at least a shift basis during tours of the ECCS rooms (in progress); (2) continue a verification step in the surveillance test to document oil reservoir filled prior to conducting the quarterly test (in progress); (3) continue oil samples/change out on an annual basis (in progress); (4) add a step to sample/change out PM to verify bearing vent is unobstructed (May 15, 1989); (5) add steps to coupling grease PM to check/align pump and motor (May 15, 1989); (6) continue vibration program on the pumps (in progress); and (7) complete replacement of CSP bearing temperature element (TE) (when failure occurred TEs were the wrong type) (May 15, 1989).

TS 6.5.1.6.g specifies that it is a responsibility of the POSRC to review facility operations to detect potential safety hazards. Failure of the POSRC to review an event such as the complete failure of a bearing on a safety related component clearly indicates a failure to implement a fundamental responsibility specified in TS 6.5.1.6.g and therefore constitutes another example of a violation of this TS requirement (317/89-04-02; 318/89-04-03).

Maintenance on the #22 AFW Pump Throttle/Trip Valve

An operator initiated Maintenance Request 38798 on January 23, 1989, that indicated the #22 AFW pump throttle/trip valve 2-MS-3988 would not reset without physical assistance. At 5:30 a.m. on March 1, 1989, the #22 AFW pump was removed from service to allow repair of the faulty trip reset mechanism using Maintenance Order (MO) 209056262A. At 4:45 p.m., the same day, the control room operator placed the handswitch 2-MS-3988-HS [illegible] shut position to test the remote trip of the valve. As described in Section 3.a of this report, a fire occurred in the control room handswitch 2-MS-3988-HS. The fire was caused by the incorrect adjustment of the overspeed trip clearance.

Factors that contributed to this maintenance activity resulting in a fire in the control room were:

(1) The MO did not provide clear and specific instructions for performing post maintenance testing. Although the SE was aware of the need to test each trip function of the AFW pump following maintenance on the throttle/trip valve, he was not involved in the planning process. Additionally, the SE was not available to review the maintenance mechanic's resetting and manually tripping the valve several times with the trip level following valve actuator assembly. Failure to test the overspeed trip function prior to testing the remote trip was a key contributor to this event.

(2) Adequate plant procedures that described removal and re-installation of the actuator were not available and the technical manual did not contain specific instructions for adjusting clearances. An information procedure had been developed by systems engineering about two years ago. This procedure clearly indicated the importance of adjusting the overspeed trip clearance. The current SE was not aware of the existence of this procedure. Failure to ensure that lessons learned from previous maintenance are incorporated in procedures and technical manuals was a contributing factor. Also, failure to establish standards for system files contributed to the delay in incorporating the alignment procedure into the technical manual.

TS 6.8.1.a and Appendix A of Reg. Guide 1.33, Revision 2, requires the licensee to establish procedures to ensure that maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with appropriate procedures. The performance of maintenance on the #22 AFW pump's throttle/trip valve on March 1, 1989, without a procedure that included specific instructions for removal, reinstallation, adjustment, and testing of the actuator for this valve is an example of a violation of TS 6.8.1.a requirements (317/89-04-01; 318/89-04-02).

As part of the licensee's corrective actions to repair the trip circuit of the #22 AFW pump's throttle/trip valve following the fire, MO 209-060-465A was issued to provide repairs as needed. Part of the repairs consisted of lifted lead activities to allow the addition of insulation over wires that received minor damage because they were adjacent to the handswitch. During inspector review of this maintenance activity, the inspector developed concern pertaining to the adequacy of administrative controls and practices associated with lifted lead and jumpers and CCI-117H, Temporary Modification Controls. The inspector's concerns pertaining to the damaged wiring repair controls were resolved by the licensee in a timely fashion. However, the programmatic concerns developed by the inspector resulted in additional inspection in the area of temporary modification controls, which is documented in Section 8 of this report.

5. Surveillance (61726)

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

The following tests were reviewed:

-- STP 0-9-2, AFAS Monthly Logic Test observed on March 1, 1989

-- STP 0-1-2, MSIV Full Stroke Test

-- RCP 1-207, Radioactive Gas Releases

-- CP-204, Specification and Surveillance of Reactor Coolant System

Snubber Testing Issue - Unit 2

On July 31, 1986, the licensee submitted an amendment request to change the surveillance requirements for visual inspection and functional testing of snubbers to conform to their new refueling interval of 24 months versus 18 months.

In June 1987, the licensee was told following the initial review of the amendment request, that the change would not be approved because NRC needed to conduct a generic study on snubbers. The licensee was advised in early 1988 of the need to satisfy the surveillance requirement for their safety related snubbers. During the early 1988 spring outage, the licensee failed to perform the surveillance testing of the snubbers. On October 14, 1988, the licensee initiated a request for extension of the time interval to satisfy TS Surveillance Requirement 4.7.8.1.c. The interval extension requested was for 54 days. One time extension was approved by NRC:NRR on March 24, 1989.

The NRR Licensing Project Manager contacted NRC:RI and the inspectors on March 24, 1989, concerning a discrepancy in the test authorization data and the test completion date. The inspector requested a meeting with the licensee's system engineer (SE) and licensing engineer (LE). The inspector discovered that the test procedure and test results had been recreated and there was no way to confirm that the data was a true representation of the original data.

The inspector notified the LE that unless verification of the original data could be made the unit did not satisfy Limiting Condition for Operation 3.7.8.1 and was in the Action Statement.

The inspector was notified by the LE at approximately 3:00 p.m. that the SE and the LE could not reconstruct or verify the data on 6 of the 47 snubbers involved. The inspector informed the LE that the NRC considers that a test without the required documentation to be a failure to perform the required Technical Specification Surveillance Testing.

The licensee notified the inspector that the POSRC had met and concurred with the inspector's interpretation and had entered the action statement at 5:45 p.m. on March 24, 1989. The licensee also notified the inspector of their intentions to test all 17 snubbers required for the HPSI and shutdown cooling systems while in Modes 5 and 6. Subsequently, the licensee notified the inspector on March 25, 1989 that an error had been committed in the number of snubbers required for Modes 5 and 6. The number of snubbers that required testing for the applicable mode increased from 17 to 86 and the licensee was planning to test 10% or 9 snubbers to satisfy the requirements. On March 26, 1989, the functional test required for Modes 5 and 6 was completed satisfactorily, hence, the surveillance requirements were satisfied and the unit exited the action statement within the allotted 72 hours. Current licensee plans call for the performance of required surveillance testing prior to entering Mode 4 operations at the completion of the refueling outage. The inspector will review the results of this testing during a routine review of surveillance testing.

The failure to perform required surveillance testing, which includes the documentation for safety related snubbers as per Technical Specification Surveillance Requirement 4.7.8.1.c is a violation (318/89-04-04).

6. 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.

7. 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.

8. Process for Temporary Changes to Plant Equipment

Federal regulations authorize licensees to make changes in the facility and procedures unless it involves a change to the Technical Specifications (TS) or an unreviewed safety question (10 CFR 50.59). The regulations also give guidance concerning what constitutes an unreviewed safety question and what reports and records are required as documentation. The licensee utilities the 50.59 process in making temporary changes to plant equipment. Permanent plant modifications also receive a 50.59 review but are handled using different administrative controls. The inspector reviewed the licensee's administrative instruction controlling temporary modifications, selected temporary modification packages and the Temporary Modification Log book. The inspector met with various members of the licensee's staff to discuss the temporary changes process.

The licensee's administrative controls for their temporary modification process utilizes CCI 117H, Temporary Modification Control. A detail review of this procedure resulted in the inspector identifying significant weaknesses which are discussed below.

10 CFR 50.59 requires the performance of a safety evaluation whenever the facility is modified as described in the Final Safety Analysis Report (FSAR). CCI 117H requires a 50.59 safety evaluation be considered only when the system/subsystem/component affected is safety related (as identified by their Q-list) and/or contains radioactive gas, liquid or particulate.

TS 6.5.1.6.d requires the POSRC to review all proposed changes or modifications to plant systems or equipment that affect nuclear safety. However, CCI 117H allows the installation of temporary modification with interim approval from two SRO licensed individuals one of whom must be the Shift Supervisor. POSRC review is then required within 14 days after implementation if the equipment affected is safety related and/or contains radioactive gas, liquid or particulate.

-- On June 28, 1988, a temporary modification (Serial No. 1-88-12) was implemented on Unit 1's hydrogen analyzer containment dome sample line isolation valve. The temporary modification prevented sampling of the containment dome by the hydrogen analyzer. The hydrogen analyzer system is described in Calvert Cliffs FSAR (Section 9.6.2.6 and figure 9-11A) and is required to be operable by Calvert Cliffs TS 3.6.5.1. This temporary modification was implemented without the performance of a 50.59 evaluation. According to the licensee's system engineers, it is not possible to obtain a grab sample from that sample point.

-- On May 23, 1988, temporary modifications (Serial Nos. 1-88-97 and 2-88-66) were implemented on both Unit 1 and 2 which slightly increased the electrical load on the emergency diesel generators during a loss of off site power. In order to provide adequate ventilation to both units' electric auxiliary feed pumps during a loss of off site power, the licensee changed the power supply of the local ventilation unit #18 to motor control center (MCC) 101. During a loss of off site power, by procedure, the MCC is switched onto the emergency busses. The MCCs and the ventilation units were not safety related, therefore there was no POSRC review or 50.59 safety evaluation performed on this temporary modification even though the modification affected nuclear safety.

In addition to the aforementioned concerns, the inspector noted that numerous temporary modification activities were excluded from the CCI 117 instruction. These included: (1) lifted lead or jumper activities that are controlled by a maintenance order and are installed for less than one shift; (2) modifications activity that is performed under a maintenance order inside a safety tagged boundary and is recommended by the implementing individual during his work period. Although these exceptions appeared to be an attempt on the part of the licensee to allow for the need to perform troubleshooting activities without the use of the temporary modification controls, the inspector noted that the end result is a confusing procedure that incorporates potentially weak features. These exceptions were discussed with appropriate members of the licensee's staff, who acknowledged the comments and concerns and agreed to incorporate appropriate guidance in the next revision to the instruction so that troubleshooting exceptions could only be used for that purpose. No temporary modifications were determined by the inspector to exist in either unit as a result of using the exceptions allowed by the instruction.

The inspector reviewed the licensee's temporary modification logs for both Unit 1 and 2. CCI 117H requires a log index be maintained as well as copies of all active temporary modification packages. When reviewed by the inspector, there were twenty seven temporary modifications listed in the log index as being active which not have their associated copies of the modification package in the log. When this was brought to the licensee's attention, the licensee found all but two of the modification packages and stated that those packages were closed.

The inspector also noted that there was no apparent time limit on temporary modifications. One current temporary modification to Unit 1 was installed on August 27, 1982. There also appeared to be a large number of temporary modifications in existence. There were over seventy active temporary modifications in existence at the time of the inspection. Plant information documents such as system descriptions and prints may not fully and accurately represent the modified hardware and performance characteristics.

On March 10, 1989, a meeting was held with licensee staff members who are involved with the temporary modification process to discuss the above concerns. The licensee stated that CCI 117H was in the process of being revised and that they would correct the weaknesses observed. They also stated they would review all active temporary modifications to determine if 50.59 evaluations should be performed and/or POSRC approval is required. As an interim compensatory measure, the licensee issued a night order on March 13, 1988, which required all proposed temporary modifications be reviewed by POSRC prior to installation.

The licensee has subsequently reviewed all active temporary modification packages that had not undergone a POSRC review (sixty-five packages). The licensee determined that six of the modifications required a 50.59 evaluation. The licensee has also determined that one of the six modifications may involve an unreviewed safety question; at the end of this inspection period, this issue was being reviewed by the Off Site Safety Review Committee.

During the conduct of the NRC's Special Team Inspection (317/89-200; 318/89-200) performed between February 27 and March 31, 1989, numerous concerns pertaining to the development and implementation of the temporary modification controls process were identified by the team inspectors. As noted above, the licensee has been aggressive in responding to the NRC's concerns in this area, and has initiated appropriate engineering review and required POSRC reviews to currently be in conformance with applicable regulatory and TS requirements. Pending the issuance of Inspection Report 50-317/89-200; 318/89-200 and further NRC evaluation in this area, the acceptability of the licensee's implementation of temporary modifications in conformance with 10 CFR 50.59 and TS 6.5.1.6.d is considered an unresolved item (317/89-04-03; 318/89-04-05).

9. Events Requiring NRC Notification (93702)

The circumstances surrounding the following events, which required NRC notification via the dedicated ENS line, were reviewed. A summary of the inspector's review findings follows or is documented elsewhere as noted below:

-- At 4:55 p.m. on March 7, 1989, the NRC was notified in accordance with 10 CFR 50.72(a)(1)(i) that an Unusual Event was declared in anticipation of a Unit 2 shutdown to Mode 3 that was required by TS 3.0.3. The shutdown was required to demonstrate the response time for the #22 SG FRV. This event is discussed in section 3.C of this report.

-- At 2:15 a.m. on March 18, 1989, the NRC was notified in accordance with 50.72(b)(1)(ii) that the #22 MSIV on Unit 2 failed one of the acceptance criteria during the performance of surveillance test procedure STP O-1-2H, MSIV Full Stroke Test. The licensee made the event determination in accordance with CCI-118 L, Nuclear Operations Section Initiated Reporting Requirements. The inspector questioned control room personnel as to why this event was reportable and learned that since they only had as little as one hour to determine if they had an event, they made calls in a very conservative manner. Upon learning of the manner in which operations personnel made event reportability determinations, the inspector discussed with operations department management representatives that it is not clearly evident that an event occurred, it is appropriate to conduct evaluation to analyze the event, determine reportability, and then initiate the notification within the appropriate time frame. A review of the details of why one of the acceptance criteria of the procedure was not met for this event resulted in both the inspector and licensee concluding that this was not a reportable event.

-- At 3:10 p.m. on March 19, 1989, the NRC was notified in accordance with 10 CFR 50.72(b)(2)(ii) that an inadvertent engineered safety feature actuation occurred at 2:30 p.m., which resulted in the injection of borated water into the Unit 1 RCS. The unit was in Mode 5 at the time. This event is further described in section 3.H of this report.

-- At 2:20 p.m. on March 20, 1989, the NRC was notified in accordance with 10 CFR 50.72(b)(2)(ii) that an inadvertent partial engineered safety feature actuation occurred at 1:20 p.m. with Unit 1 in Mode 5. This event is documented in section 3.I of this report.

-- At 3:45 a.m. on March 24, 1989, the NRC was notified in accordance with 10 CFR 50.72(b)(2)(ii)(D) that the failure of a Unit 1 instrument air boundary check valve to pass a back leakage test could prevent the proper functioning of the salt water system. This event is discussed in section 3.D of this report.

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 was reviewed:

LER No.	Event Date	Report Date	Subject
Unit 1			
89-02	02/14/89	03/16/89	Improper Leads Lifted on Containment Purge Valves

No unacceptable conditions were noted.

11. Review of Periodic and Special Reports (90713)

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

-- February 1989 Operating Data Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated March 10, 1989.

-- Report of Changes, Tests and Experiments dated, March 14, 1989.

-- Annual Report of Failures and Challenges to PORVs and Safety Valves for the Period January 1, 1988 through December 31, 1988, dated February 28, 1989.

-- 1988 Steam Generator Inspection Results Report, Unit 1 Steam Generators 11 and 12 Eddy Current Testing Final Report for the period April-June, 1988, dated February 24, 1989.

No unacceptable conditions were identified.

12. Licensee Action on Previous Inspection Findings (93702 and 92701)

(Closed) Unresolved Item (50-317/85-28-04) Hydrogen Recombiner Inspection. The inspector reviewed STP-M-581, Hydrogen Recombiner Inspection and determined that the procedure included provisions for documenting results of the inspection and acceptance criteria. This item is closed.

(Closed) Unresolved Item (50-318/85-34-01) Temporary Procedure Changes. The inspector reviewed memorandum from operations personnel attesting that the GSNO counseled all shift personnel on proper documentation of temporary procedure changes. In addition, formalized guidance was provided to shift personnel via GSNO Standing Instruction 86-1 which was also reviewed. This item is closed.

(Closed) Unresolved Item (50-318/85-32-02) Engineered Safety Features Actuation. The inspector reviewed General Supervisor of Nuclear Operations Standing Instructions which specifies plant evolutions that required Senior Reactor Operator presence to ensure plant safety and operability of equipment. Among those evolutions is Engineered Safety Features Actuation System startup, shutdown and operations testing. This item is closed.

(Closed) Unresolved Item (50-318/85-20-03) Failure to Follow Procedures for Environmental Qualification Inspection (EQ). The inspector has reviewed the licensee's files and found them to be in compliance with the procedures in question during previous EQ inspections. This item is closed.

(Closed) Inspector Follow Item (50-317/85-15-01) Salt Water Pump Suction Bell Erosion/Corrosion. The inspector reviewed maintenance orders for salt water pumps #13, 21 and 23 which occurred following the inspection of the above mentioned pumps during the third quarter of 1985. The results showed no evidence of holes on the suction bells of the pumps. In addition, design engineering performed an analysis on the salt water pumps assuming gross degradation of the suction bells. The conclusions were that with the assumed gross damage, there would be sufficient strength remaining in the suction bells to resist seismically-imposed loads. This item is closed.

(Closed) Unresolved Item (50-317/85-03-02) Post Modification Testing of Reactor Trip Breakers. The inspector reviewed a copy of CCI 200L, Appendix 200.30, Post Maintenance and Operability Testing. The CCI clarifies Post Maintenance Testing requirements for all safety-related equipment. This item is closed.

(Closed) Unresolved Item (50-318/87-28-01) Atmospheric Dump Valve (ADV) Performance Problem. Performance problem with #11 ADV was identified to be a lock nut on the stem loosening and becoming jammed in the packing gland. The licensee has removed the lock nuts from Unit 1 ADV's. The gasket material on the ADV's has been replaced with material capable of withstanding higher temperatures. In addition, the enclosures around the ADVs have been removed to reduce the temperature levels. Procedures have been developed to aid mechanics during the overhaul of the ADVs. This item is closed.

13. <u>Unresolved Items</u> (93702)

Unresolved items require more information to determine their acceptability and and one such item is discussed in section 8 of this report.

15. <u>Exit Interview</u> (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.