

DCS Nos.	50317830295	50317821230	50318830101
	830202	821229	830107
	830131	821227	830104
	830126	821224	830112
	830118	821223	830118
	830101	821219	830131
	821118	821215	830202

U.S. NUCLEAR REGULATORY COMMISSION  
Region I

Docket/Report: 50-317/83-02  
50-318/83-02

License: DPR-53  
DPR-69

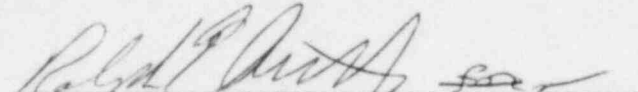
Licensee: Baltimore Gas and Electric Company

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

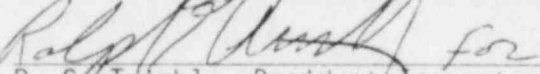
Inspection At: Lusby, Maryland

Dates: January 11 - February 15, 1983

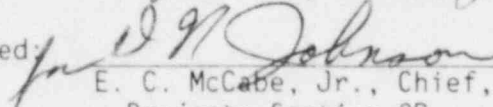
Submitted:

  
R. E. Architzel, Sr. Resident Inspector

2/22/83  
date

  
D. C. Trimble, Resident Inspector

2/22/83  
date

Approved:   
E. C. McCabe, Jr., Chief, Reactor  
Projects Section 2B

2/23/83  
date

Summary:

January 11 - February 15, 1983: Inspection Report 50-317/83-02, 50-318/83-02.  
Areas Inspected: Routine resident inspection (247 hours) of the control room, accessible parts of plant structures, plant operations, radiation protection, physical security, fire protection, plant operating records, maintenance, surveillance, radioactive waste releases, open items, TMI Action Plan items, Plant Operations and Safety Review Committee activities, and reports to the NRC. No violations were identified.

## DETAILS

### 1. Persons Contacted

The following technical and supervisory personnel were contacted:

M. E. Bowman, Principal Engineer, Nuclear Fuel Management  
J. T. Carroll, General Supervisor, Operations  
J. A. Crunkleton, Supervisor, Electrical Maintenance  
R. E. Denton General Supervisor, Training/Technical Services  
C. L. Dunkerly, Shift Supervisor  
W. S. Gibson, General Supervisor, Electrical & Controls  
J. E. Gilbert, Shift Supervisor  
D. W. Latham, Principal Engineer, OL&S Unit  
W. J. Lippold, Supervisor Nuclear Fuel Management  
J. F. Lohr, Shift Supervisor  
W. T. Lyons, Engineering Technician, PMD  
R. O. Mathews, Assistant General Supervisor, Nuclear Security  
G. S. Pavis, Engineer, Operations  
J. E. Rivera, Shift Supervisor  
L. B. Russell, Plant Superintendent  
J. A. Snyder, Supervisor, Instrument Maintenance Unit 2  
J. A. Tiernan, Manager, Nuclear Power Department  
D. Zyriek, Shift Supervisor

Other licensee employees were also contacted.

### 2. Licensee Action on Previous Inspection Findings

(Closed) Unresolved Item (317/82-18-05, 318/82-16-03) Submit a Revised Schedule for the Noble Gas Monitoring System. The inspector reviewed a letter dated January 21, 1983, from the licensee to the NRC, Division of Licensing, detailing implementation problems which have been experienced with the Post-Accident Sampling System (PASS) and the Noble Gas Stack Monitor. The PASS has been taken out of service for vendor recommended modifications, and the licensee provided a revised commitment date of June 1, 1983, for system operability. The Noble Gas Stack Monitor was stated to be installed and functional; however, its performance to date was not within the requirements of the design specifications. The licensee stated that they were pursuing these problems with the equipment vendor and expected to complete corrective action by June 1, 1983. In the interim compensatory measures have been implemented as required for the short term requirements required by NUREG 0578. These items remain open pending completion and reinspection (documented in the NRC's TMI Action Plan Tracking System).

(Closed) Violation (318/82-02-02) Failure to Specify Correct Code for Weld Repairs. The licensee responded to this item in a letter dated 3/17/82. The inspector verified the licensee's corrective actions which included correction of the Weld Authorization Traveler in question and training for welding foremen and senior welders in the proper completion

of Weld Authorization Travelers. Calvert Cliffs Training Memorandum 82-M-68, dated April 2, 1982, documented completion of training in ASME Code and Weld Authorization Traveler documentation requirements, and included attendees in the above-mentioned categories.

(Closed) Inspector Follow Item (317/82-03-01, 318/82-03-01) Repair/-Replace Heat Tracing and Re-insulate No. 11 RWT Recirculation Piping. The inspector examined external portion of No. 11 RWT recirculation piping and noted that the heat tracing and insulation had been reinstalled (MR-0-82-450).

(Closed) Unresolved Item (317/82-23-03). Design Adequacy of the Chemical and Volume Control System (CVCIS). Section 7B of Inspection Report 50-317/82-29 and 50-318/82-25 described modifications completed on Unit 1 to ensure West Piping Penetration/Letdown Heat Exchanger Room pressure sensor operability. During this report period, the inspector examined similar modifications accomplished on Unit 2 and confirmed that an air flow direction test (with Penetration Room Exhaust fans running) had been successfully completed.

(Closed) Inspector Follow Item (318/81-18-06) Implement Formal Repacking Program for Valves. The inspector reviewed the licensee's program, which was implemented by initiating a new set (3 for each unit) of preventive maintenance cards (64-MR-5, 6, 7). These preventive maintenance actions require that Reactor Coolant System valves be inspected while hot (if possible) on a refueling outage basis. Valve packing is required if the gland shows boric acid, downstream piping is hot or the gland has bottomed out. A Facility Change Request (81-141) is in progress to replace critical packed valves in the Reactor Coolant System with hermetically sealed valves.

(Closed) Violation (317/81-27-01, 318/81-25-03) Failure to Maintain Insulation on the Boric Acid System Piping. The licensee responded to this item in a letter dated February 12, 1982. The inspector verified the licensee's corrective action. A memorandum was issued (Shop/Lab Memorandum M-29, dated 2/8/82) to require that maintenance items remain open pending reinstallation of insulation/heat tracing following any maintenance activity which requires the removal of these items. Mechanical Foremen are directed, via the memorandum, to schedule reinsulation. The licensee also revised Bechtel specification 6750-E-39 for the Boric Acid System Heat Tracing and Insulation to allow the use of fiberglass insulation with aluminum jackets on the piping in these systems. The inspector toured both Boric Acid Storage Tank Rooms and the Charging Pump Room and observed that the piping required to be heat traced had been reinsulated. The inspector questioned the licensee concerning the properties of the fiberglass insulation which was being reinstalled on the stainless steel piping in lieu of the originally specified calcium silicate material. The licensee showed the inspector the specification data for the insulation which was being used (Johns-Manville Micro-Lot 650 Heavy Density Pipe Insulation). The insulation was specified as non-corrosive and had a thermal conductivity within the range of values

required by the Bechtel specifications for the Boric Acid Piping Insulation. The inspector reviewed the specifications and noted that controls were also required to ensure that the calcium silicate insulation did not possess unacceptable levels of leachable chloride, the presence of which can cause accelerated corrosion on austenitic stainless steel piping. The inspector noted that Regulatory Guide 1.36, Non-metallic Thermal Insulation for Austenitic stainless steel issued 2/23/73, required testing of insulation material to verify that the leachable chloride and fluoride ion concentrations are within acceptable levels and that sufficient quantities of the corrosion inhibiting ions (sodium and silicate) are present in the insulation. The inspector questioned the licensee concerning how the installed insulation compared with the requirements of the Regulatory Guide. The licensee noted that they had not committed to Reg. Guide 1.36 in their Quality Assurance Plan. A review of other Bechtel specifications, including specification 6750-M-338, Plant Insulation-Except Reactor Coolant Insulation and Steam Generator Insulation and related correspondence revealed that fiberglass insulation had been approved for installation in both Unit 1 and 2 on a number of stainless steel piping systems. All of the fiberglass insulation specified was certifiable to Military Specification MIL-I-24244. This specification contains the same graph of acceptable analyses for chloride and fluorides and corrosion inhibitors as that shown in Regulatory Guide 1.36. Both the Reg Guide and the Military Specification require a qualification test of the insulating material and laboratory analysis of each lot of insulation to verify that a lot is representative (chloride, fluoride, sodium and silicate ions). The licensee was not specifically requiring that purchased insulation comply with the Military Specification, the testing of which would require additional funds in the purchase order. Because the licensee had not committed to Regulatory Guide 1.36, and insulation being used on stainless steel piping was of a type certifiable by a military specification which contained the same requirements as the Regulatory Guide, this item is considered closed.

(Open) Violation (317/82-30-04) Non-Conformance in the Installation of Temporary Shielding. The licensee made a best estimate (based on employee recollection) of the number of temporary lead shield blankets used at various locations in the Unit 1 Containment during the Spring 1982 Refueling Outage. As discussed in Inspection Report 50-317/82-30, 50-318/82-27, licensee estimates showed that more shielding than the maximum number of blankets specified in related Facility Change Request 82-1030 was added in only one location (Chemical and Volume Control System valves 1-CV-515 and 1-CV-516). Using the best estimate number of shield blankets on 1-CV-515 and 516, an engineering evaluation was completed during this reporting period which showed that the extra weight added by the shielding would not have adversely affected plant components. The inspector examined a picture of the 1-CV-515 and 516 area taken during the refueling outage. That picture could not accurately be used to determine the exact number of shield blankets used. However, the picture did indicate that the licensee's shield block estimate was reasonable.

(Closed) Unresolved Item (317/81-13-04; 318/81-13-01) Technical Specification (TS) Limit for Pressurizer Level. On 1/25/83, Unit 1 TS Amendment 80 and Unit 2 Amendment 63 were issued which provide a wider operating band for pressurizer level. The wider operating band will provide increased operational flexibility and should reduce the number of Licensee Event Reports resulting from the exceeding of LCO limits on pressurizer level.

(Open) Unresolved Item (318/82-27-04). Unplanned Safety Injection due to Operator Error in Operating Pressurizer Spray. The Safety Injection Actuation on 1/11/83 caused a Letdown Isolation as designed. On 1/12/83 the inspector reviewed the "Plant Transient and Operating Cycles" Log to see if the thermal transient resulting from the Letdown System flow stoppage and the accompanying Charging Pump Injection of colder Boric Acid Storage Tank Water into the Reactor Coolant System had been entered. Such an entry is required by Calvert Cliffs Instruction (CCI) 301. The transient had not been logged. It did appear though, as evidenced by earlier entries, that the log was being used on a regular basis with the most recent entry for this category of transient dated 1/6/83. The inspector noted the missing entry to the Shift Supervisor and the General Supervisor-Operations (GSO), who stated they would ensure the above transient would be logged. The typical licensee practice is for each shift's Senior Control Room Operator (SCRO) to log plant transients as they occur. The GSO stated that each month a particular SCRO is given lead responsibility for verifying that all applicable transients are logged. The inspector pointed out to the GSO that 71 events had been logged under the category of "Loss of Charging/Letdown or Letdown/-Regenerative Heat Exchanger Isolation". Since CCI 301 specifies a limit of 50 cycles for loss of letdown flow, the inspector asked the GSO if someone in the licensee's organization was tracking these transients and verifying that the 50 cycle limit had not been exceeded. The GSO stated that this tracking was being done. The inspector then discussed this item with the Technical Support Engineer who had been assigned to seek relaxation of the maximum number of allowed cycles. That engineer stated he has reviewed all of the loss of letdown flow events listed in the transient log. The transient log does not record sufficient information to determine the severity of a transient, so he had to research past operating logs. In general, the engineer found that the operators were conservatively recording events in that relatively minor events, such as a flow interruption of 15 seconds duration, were being logged. The engineer stated that no guidance existed regarding the threshold of transient severity level which must be exceeded to count as a design cycle. Therefore, the number of design cycles actually experienced to date for loss of letdown flow is difficult to estimate, but is in the range of 38-45. The engineer stated that an effort is underway to have the NSSS vendor justify a greater maximum cycle limit. Initially, the vendor estimated that the limit on loss of letdown cycles can be doubled or tripled.

Because the transient log has been updated on a continuing basis and because relatively minor events are being recorded, the inspector considered the failure to log the 1/11/83 Unit 2 transient to be an isolated case. The inspector will follow the licensee's status with respect to letdown flow stoppage transients until the licensee determines that adequate margin exists between actual transients and maximum allowed transients.

3. Review of Plant Operations

a. Daily Inspection

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

-- January 16, 19, 21, 26, 27, 28, February 2, 3, 4, 7, and 9, 1983.

No unacceptable conditions were identified.

b. Weekly System Alignment Inspection

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

-- Lineup of major flowpath valves and breakers for the Unit 2 High and Low Pressure Safety Injection systems on 1/19/83.

-- Unit 1 Instrument Air System on 2/3/83.

-- Unit 1 Service Water Lineup in the Service Water Pump Room on 1/27/83.

-- Unit 1 and 2 CVCS Lineup in the Charging Pump Rooms on 2/7/83.

No unacceptable conditions were identified.

c. Biweekly Inspection

Verification of the following tagouts indicated the action was properly conducted.

- Tagout 718 dated 1/8/83, Unit 2 Safety Injection Tank Outlet Valves verified on 1/19/83.
- Tagout 181, Unit 1 Containment Tendon Inspection Platform checked on 1/26/83.

Boric acid tank samples were compared to the Technical Specifications. Tank levels were also confirmed.

No unacceptable conditions were identified.

d. Other Checks

During plant tours, the inspector observed shift turnovers, security practices at vital area barriers, completion and use of radiation work permits, protective clothing and respirators. Personnel monitoring practices, and area radiation and air monitor use and operational status were reviewed. Equipment tagouts were sampled for conformance with LCO's. Plant housekeeping and cleanliness were evaluated. Other LCO's, including RCS Chemistry and Activity, Secondary Chemistry and Activity, watertight doors, and remote instrumentation were checked.

- On 1/28/83 the inspector noted that the radiation area posting sign was not completely in place surrounding the Unit 1 Refueling Water Storage Tank. The inspector informed the Radiological Control Shift Supervisor who dispatched a technician to replace the barrier. The inspector observed that the proper posting was in place later the same day.

No unacceptable conditions were identified.

4. Review of Events Requiring One Hour Notification to the NRC

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

- a. A partial actuation of Engineered Safety Features (ESFAS) occurred at 12:17 p.m. on 1/31 when a ground on the #22 120 VAC Vital Bus apparently initiated a voltage transient. Actuations included Undervoltage (resulting in the loss of #24 4KV Vital Bus), Turbine Trip (resulted in Turbine/Reactor Trip from 100%), Letdown Isolation, and realignment of some Safety Injection valves (resulted in addition of boric acid to the RCS). The transient also resulted in the loss of #22 Vital Inverter (blown DC input fuses). The loss of #22 Vital Bus resulted in no power to the Loss of Coolant Incident Sequencer so the Safety Injection pumps did not start. The inspector observed post trip recovery actions from the Control Room and reviewed computer printouts for the sequence of events and alarms received.

Several minutes into the recovery the inspector noted that the Containment Spray pumps remained in "Pull-to-Lock" (PTL). The operator had placed this equipment in PTL to prevent spraying down the containment upon the inadvertent actuation. The B channel actuations had been reset so the operator restored the handswitches to normal. Earlier in the day electricians had been investigating an existing ground on the Vital Bus (MR O-83-1041 initiated on 1/29/83). A ground was found in the power supply for the #22 RCS Loop Cold Leg Temperature Instrument and corrected.

Following the trip the unit was restored to normal HOT STANDBY and a Facility Change initiated to re-fuse vital AC loads (previous actuations have been partially attributed to improper fusing). During the replacement of fuses, which included placement of jumpers across the fuse holders, a technician caused a short on the #22 Vital AC Bus, initiating another voltage transient at 9:36 p.m. All ESFAS Channel B Actuations occurred (Steam Generator Isolation, 4KV Bus Undervoltage, Safety Injection, Recirculation Actuation, Containment Spray, and Chemical & Volume Control Isolation). The #22 Vital Inverter was not lost this time. A Reactor startup was in progress (no trip occurred). Containment Spray was blocked before the Containment was actually sprayed (I&C technicians were in the Containment at the time of actuation and verified that no spray occurred). RCS pressure remained above the shutoff head of the SI pumps (2250 versus 1260 psia) so no injection occurred. The cause was immediately identified, corrected, and equipment restored to normal. The inspector reviewed Control Room logs, computer print-outs, and discussed the event with Operations Personnel. Both events on 1/31 were logged as transients (Loss of Letdown) in the Unit 2 Transient Log. Main Steam Isolation Valve (MSIV) 22 was found to have a blown O-ring which was replaced prior to reopening the MSIV's. Following restoration from the ESFAS actuations at 9:39 p.m. on 1/31, the startup was continued and the reactor was made critical at 10:10 p.m.. Pressurizer level deviations (normal) occurred during restart and were reported to the NRC Operations Center. Findings are discussed in paragraph 4.g below.

- b. At 6:55 a.m. on 1/26/83 Unit 1 tripped (on low Steam Generator (SG) level) from 100% power. The trip resulted when an operator, intending to open the #11 Diesel Generator breaker (152-1103) for 4KV bus 11, mistakenly opened the feeder breaker for 480 VAC Bus 11B (152-1102). This caused a loss of power to both Main Feedwater Pump (MFP) Speed Controllers. MFP speed and SG levels decreased. Power was restored to the MFP speed controllers, and the Control Room Operator increased MFP speed too rapidly in an effort to restore SG levels. The MFP's then tripped on low suction pressure and SG levels decreased to the reactor trip setpoint. The inspector discussed the event with operations personnel, reviewed the



"Sequence of Events" computer printout, and examined the plant electrical control board. The inspector noted that breakers 152-1103 and 152-1102 are immediately adjacent to each other on the control board. Plant protection systems functioned as designed. The inspector had no further questions.

- c. At 2:10 p.m. on 1/18/83 the licensee confirmed earlier sample analyses that indicated a stratification of boron in the Unit 1 Refueling Water Tank (RWT). Boron concentration at the bottom of the tank was 2973 ppm (Technical Specification (TS) maximum allowed concentration is 2700 ppm). The licensee initiated a plant shutdown at 3:10 p.m. to comply with TS 3.5.4 and began recirculating the RWT with the Spent Fuel Pool Cooling Pumps. About 4:00 p.m., RWT boron concentration was 2600 ppm (back within TS limits), and the unit was returned to full power. The licensee initially attributed the cause of the RWT stratification to a valve lineup error in the normal RWT recirculation flowpath. The inspector discussed the event with Operations and Chemistry Personnel and the General Supervisor of Operations and reviewed Chemistry sample results. The licensee is still investigating the problem. The NRC will follow the licensee's investigation (317/83-02-02).
- d. Unit 1 was shutdown at 8:50 a.m. on 2/5/83 when a second Control Element Assembly (CEA) reed switch position indication channel (for CEA 26) failed in regulating group #3. Technical Specifications 3.1.3.3 and 3.0.3 require a shutdown under these circumstances. An Unusual Event was declared, as required by the Emergency Plan, at 9:45 a.m. The reed switch position indication channel for CEA 28 had failed earlier. While shutdown, the licensee replaced reed switch stacks for five CEAs, including CEAs 26 and 28, and re-started the unit on 2/7/83. The inspector had no further questions.
- e. At 8:13 a.m. on 2/2 another partial Engineered Safety Features (ESF) Actuation occurred when #22 vital AC inverter tripped. Actuators included undervoltage, resulting in the loss of the 24 4KV Bus (power restored when #21 Diesel Generator started); Turbine Trip resulting in a Turbine/Reactor Trip from 30% power; and Chemical and Volume Control Isolation, resulting in a loss of Letdown. No cause was known for the loss of the inverter. The backup power supply was placed on #22 Vital Bus and the unit placed in normal HOT STANDBY conditions. Because of repeated actuators of ESF, the NRC requested a meeting with the licensee to discuss the licensee's analysis of the actuators and their planned corrective actions. The inspector reviewed the sequence of events and other computer printouts associated with this event. Licensee corrective and investigative actions were reviewed and observed by the inspector (see paragraph 4.g below).

- f. At 7:32 p.m. on 2/2, with Unit 2 in Mode 3, another partial Engineered Safety Features Actuation occurred when #21 Vital AC bus was being shifted from its backup (vital AC) to normal (inverter) power supply. The cause was thought to be either a malfunction in the transfer switch (make-before-break type) or actuation of the inverter's current limiting circuitry during the transfer. The transfer was being conducted following testing of the inverter to try to determine the cause(s) of recent ESF actuations. Channel A actuations included Containment Spray, Safety Injection, Containment Isolation, Recirculation Actuation, Undervoltage, resulting in the loss of the #21 4KV bus (power restored when #12 Diesel Generator started), and Chemical and Volume Control Isolation, resulting in a loss of Letdown. Rapid operator action prevented spraying the Containment. RCS pressure was above the shutoff head of the High Pressure Safety Injection pumps. Systems were restored to normal for HOT STANDBY and testing of ESF Actuation Systems and the 120 Volt Vital AC system continued through the night. The inspector reviewed the event with operators, technicians and other licensee personnel. Portions of the licensee's test program were observed. The actual cause of the actuation was later found to be technician reversal of the inverter power leads following their lifting during a test of the current limiting circuitry. These leads were lifted under MR E-83-54 and replaced on the reversed terminals following the testing (following the PORV Actuation/Safety Injection on 2/3 - see below). The result was that the inverter was synchronized 180 degrees out of phase when a power transfer was attempted. The current limiter apparently correctly limited the current transient such that the inverter was not damaged and power was not lost to the vital bus.

An additional factor confusing the investigation was the appearance of "hidden" trips which were causing the BL ESFAS Actuation Cabinet to actuate when only one sensor cabinet was deenergized. Five defective signal isolators were found to be sending partial trip signals (hidden) to the Actuation Cabinet (MR I-83-2042 dated 2/3/83). Findings **are discussed in paragraph 4.g below.**

- g. An inadvertent opening of both Unit 2 Power Operated Relief Valves (PORV's) occurred at 6:03 p.m. on February 3, 1983. The reactor was in MODE 3 at normal operating pressure (2250 psia). Reactor Coolant System pressure decreased to 1520 psia before the operators diagnosed the situation and overrode the PORV's shut about 30 seconds after actuation. A partial Safety Injection (Channel B) occurred at the pressure setpoint (1780 psia), however pressure remained above the shutoff head of the High Pressure Safety Injection Pump (1260 psia). The Quench Tank rupture disk blew and Containment humidity increased but there was no evidence of a liquid release. Apparently only steam was released. There was no increase in the site release rate of radioactive materials. Pressurizer level increased from 150-190" during the transient due to Letdown Isolation and the charging pumps. Reactor Coolant Pumps were tripped and other actions taken as required by the Emergency Operating Procedure. The Safety Injection was reset by 6:15 p.m. and normal pressure restored by 6:50 p.m.

The cause of the PORV's opening was operator error in deenergizing the wrong Reactor Protective System Channel (RPS) prior to a test of the #21 Vital 120 VAC Bus power transfer switch (Inverter to AC line). An unsuccessful transfer attempt earlier in the day had resulted in blowing newly installed fast acting fuses when Channel A was reenergized. Channel D was mistakenly deenergized. A Senior Control Room operator was directed to deenergize Channel A RPS. The operator deenergized the D Channel. (He stated that he thought that he was looking at the A panel. The Control Room at Calvert Cliffs uses mirror image symmetry for Control Boards, switches and panels except for the RPS cabinets, which are the same [left to right] when viewed from the front. The result is that the Unit 2 Channel D RPS Cabinet is in the same relative location [as determined by mirror image symmetry] as the Unit 1 Channel A RPS Cabinet.) When the transfer was attempted it was unsuccessful, resulting in a loss of the Vital Bus which powers Channel A. As designed, the Pressurizer Pressure Channels opened the valves when the 2 out of 4 channel logic was satisfied. Channel A Engineered Safety Feature Channels had been disabled prior to the transfer to avoid inadvertent actuations in the event the power transfer was not successful; a condition which had occurred earlier in the day and also on February 2, 1983. The licensee notified the NRC via ENS at 6:45 p.m. and the Senior Resident Inspector about 7 p.m.

The inspector returned to the plant and observed the licensee's recovery actions, the sequence of events following the actuations and investigation of the cause of the actuations.

As described above in the event of 2/2/83, electricians had reversed the output leads of the #21 Vital AC Inverter during the load limiter test on 2/2/83. One additional attempt (following the PORV opening/Safety Injection Actuation) at paralleling the vital AC Inverter out of phase was tried about 4 a.m. on 2/4. The DC Input fuses again blew and prevented inverter damage. Following this, circuit tests were performed, drawings checked, and the wiring error was found. A load test showed the Inverter to be still capable of carrying design loads and a short circuit test was successfully conducted demonstrating acceptable Inverter operation with the circuit limiter removed.

The inspector noted that MR E-83-54 specified the correct drawing for the output wiring of the Inverters and showed the arrangement of the synchronization circuit. A Quality Control call number had been issued and a QC inspector present during the testing. These actions had not prevented improper installation of the Inverter power leads, nor had sufficient investigative action been taken following the initial parallel attempt to identify the cause of the Inverter tripping nor following a subsequent attempt on 2/3/83 (prior to the event at 6:00 p.m. on 2/3/83). The Inverter was synchronized four times out of phase before the cause was identified.

Following these events, a meeting was requested by the NRC with the licensee to discuss the history of ESFAS actuations at Calvert Cliffs and the specific instances of operator/technician error, to include the licensee's corrective actions, both taken and planned. The meeting was scheduled at NRC Headquarters following the report period (2/24/83). Unresolved Items (318/82-25-02), dealing with the high frequency of technician and operator error induced actuations of ESFAS; (318/82-27-02), dealing with the fusing coordination problem; and (318/82-27-03), dealing with the design adequacy of the vital AC power supply for the ESFAS loads all relate to the ESFAS actuations on 1/31 and are updated by this report. Licensee actions and analysis were to be addressed in the meeting referenced above.

#### 5. Radioactive Waste Releases

Records and sample results of the following radioactive waste releases were reviewed to verify conformance with regulatory requirements prior to release.

- Gaseous Waste Permit G-006-83, 1/19/83 Vent of Unit 2 Containment via ECCS Sump, reviewed on 1/24/83.
- Liquid Release Permit M-008-83, 1/17/83 Release of #11 Miscellaneous Waste Monitoring Tank, reviewed on 1/24/83.

No unacceptable conditions were identified.

#### 6. Observation of Physical Security

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

No unacceptable conditions were identified.

#### 7. Review of Licensee Event Reports (LER's)

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

<u>LER No.</u>	<u>Event Date</u>	<u>Report Date</u>	<u>Subject</u>
<u>Unit 1</u>			
82-75	12/15/82	1/14/83	#11 Containment Cooling Unit (CCU) tripped, #12 DG, Emergency Power source for #14 4KV Bus and #13 & #14 CCU's inoperable.
82-76	12/19/82	1/17/83	#12 Containment Air Cooler Fan inoperable.
82-77	12/24/82	1/21/83	Incore Detector Monitoring System inoperable.
82-78	12/18/82	1/17/83	Containment Particulate Radiation Monitor inoperable.
82-81	12/27/82	1/14/83	Snubber 1-83-53 inoperable.
82-82	12/27/82	1/21/83	Continuous CEA Motion Inhibit signal in effect causing CMI to be inoperable whenever CEA's were moved.
82-83	12/29/82	1/28/83	RPS Channel A trip units for low SG level, low SG pressure & Thermal Margin Low Pressure bypassed for maintenance.
82-84	12/23/82	1/21/83	Sequencer initiated alarm inoperable.
82-85	12/30/82	1/27/83	ESFAS AL sequencer inoperable.
82-86	11/18/82	1/28/83	Oyster samples showed AG-110m to be 532+/-12 and 458+/-12 pCi/kg (wet).
83-01	1/01/83	1/27/83	AFW Flow Indication inoperable.
83-04	1/01/83	1/31/83	Containment Sump Level Alarm inoperable.
82-23**	5/14/82	9/30/82	Unplanned dilution of RCS due to Steam Generator Tube Leakage.

Unit 2

83-01	1/04/83	2/03/83	Pressurizer pressure controller and Shutdown Cooling loop return isolation valve inoperable.
83-02	1/01/83	1/31/83	ERV-402 inoperable.
83-03*	1/12/83	1/26/83	AFW valves 4511 & 4512 failed open causing abnormal flow during over cooling event.
83-05	1/07/83	1/19/83	Shutdown Cooling flow lost during surveillance test.

\* This item addressed in Section 11.

\*\* Update LER.

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

-- Unit 2/82-29 Containment Particulate Monitoring System. This LER addressed the inoperability of the system due to a bent detector cable causing the detector power leads to pull free, and was previously inspected and left open in report 318/82-16. The inspector observed the completed installation of the enclosure of the cabinet and installation of a lock as committed by the licensee.

-- Unit 2/82-34 Loss of Salt Water Flow. This event report stated that a piece of a failed pin (the pin connecting the valve disc to the operator end stub shaft) would be analyzed in an attempt to ascertain its failure mode for use in determining further corrective action. During this reporting period, the inspector reviewed the summary results of the completed pin analysis. That analysis, dated 10/28/82, stated that the fracture surface was so severely worn that the mode of failure could not be determined. The licensee is considering the use of lower sulfur content monel for these pins because sulfide inclusions become stress risers where fatigue cracks can propagate and eventually lead to failure.

- Unit 2-About 9:25 p.m. on 2/11/83, Unit 2 Reactor Coolant System (RCS) Dose Equivalent (D.E.) I-131 reached a peak level of 1.07 uci/gram (Technical Specification limit is \$1.0 uci/gram) following a rapid power reduction from 100% to 40% power. I-131 D.E. activity then decreased to 0.27 uci/gram. Prior to the power reduction I-131 D.E. activity was about 0.4 uci/gram. The licensee stated that the elevated I-131 D.E. activities are caused by one or more fuel pin cladding leaks. The licensee will submit an LER describing this event.

#### 8. Plant Maintenance

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

- MR I-83-2042, Investigate Hidden trips on ESFAS Actuation Cabinet BL, observed on 2/3/83.
- Observed test of newly installed power transfer switch on #21 vital inverter on 2/4/83.
- Observed corrective maintenance on the Diesel Fire Pump on 1/29/83.
- MR 0-83-1189, observed replacement of Unit 2 Quench Tank Rupture Disk on 2/3/83.

The inspector reviewed portions of the modifications and testing of the Unit 2 Vital AC Inverters. The Safety Evaluation (Supplement 3) dated 2/2/83 for Facility Change 83-1001, which addressed removal of the Inverters' current limiting feature was reviewed. Maintenance Action MR E-83-51, implementing the FCR, was observed. During the testing following modifications (15 amp fast blow fuses shorted between phases) instantaneous currents as high as 280 amperes were experienced prior to the fuse blowing. There was no damage to the Inverters nor notable voltage transient on the Vital AC Bus.

On 2/4 the inspector observed four short circuit tests on Vital Bus #21 using 15 amp fast blow fuses (following removal of the current limiting circuitry and correction of the inverter lead reversal problem [paragraph 4]).

On 2/4/83, while observing testing of a newly installed transfer switch on #21 Vital Inverter, the inspector noted the following problem. The transfer switch selects either the inverter or Inverter Backup Bus #21 as the power supply for #21 120 VAC Vital Instrument Bus. All four 120 VAC Vital Instrument Buses on a unit share the same backup power supply bus. Each inverter transfer switch is equipped with a key lock which captures the operating key when the switch is placed in the backup power supply position. Previously, the same key fit all inverter transfer switches. The licensee administratively allows only one transfer switch key in the Control Room to prevent the transfer of more than one inverter to the backup bus at one time. The inspector noted that the newly installed transfer switch has a different type lock with a different key. The inspector informed the General Supervisor-Operations that existing administrative controls were now no longer sufficient to prevent placing more than one vital instrument bus on the backup power supply at one time. The General Supervisor-Operations agreed to look into the problem. The inspector will follow licensee corrective action (318/83-02-02).

#### 9. Surveillance Testing

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

- TSP 101, Revision 0 approved 1/7/83. Auxiliary Feedwater Modified FCR 79-1002, Hot Preoperational Test observed on 1/21/83.
- TSP 99, Revision 0, approved 12/13/82. Testing of third train, motor driven Auxiliary Feedwater Pump.

No unacceptable conditions were identified.

#### 10. Unit 2 Startup Testing

The inspectors reviewed and observed portions of the startup test program for Unit 2 from the Refueling Outage for Cycle 5. The Nuclear Fuel Management-Shift Engineer Log for the Unit 2 startup program was reviewed. PSTP-2, Unit 2 Cycle 5 Initial Approach to Criticality and Low Power Physics Testing, Revision 4 dated 1/4/83 and PSTP-3, Unit 2 Cycle 5 Escalation of Power Test Procedure, Revision 4 dated 1/7/83 were reviewed. The inspectors observed portions of the dual CEA Symmetry Checks, Essentially All Rods Out Boron Concentration, Initial Criticality, Isothermal Temperature Coefficient measurements, and Integral Non-overlap Rod Worth measurements. Additionally, a tour of the Unit 2 Containment was made after the licensee's initial closeout inspection. Various equipment and locked valves were checked, including Containment Spray, Purge, Safety Injection Tanks, and Cooling Water to the Containment Filter Units.



Subsequent to the refueling operations, and prior to initial startup of Cycle 5, the licensee had discovered that Control Element Assembly (CEA) 44 had a malfunctioning reed switch position indication channel. The malfunction was found to be in the stack of reed switches, repair of which would have taken five days to accomplish. The Technical Specification Limiting Condition for Operation (LCO) 3.1.3.3 requires that all shutdown and regulating CEA reed switches and pulse counting channels be operable. The CEA's pulse counting position indicating channel remained operable and the CEA was known not to be immovable. The licensee had previously submitted applications, and received license amendments (48 and 54 for Unit 2) to allow continued operation and transition from Mode 3 to Mode 2 with one CEA position indicating channel per CEA group inoperable. Technical Specifications Action Statement 3.1.3.3.b.2 was issued detailing the required action if the inoperable position indication existed prior to reaching a CEA full out position. The action required that the inoperable CEA be moved to a full out position and verified to be fully withdrawn via a full out indicator. Associated action statement 3.1.3.3.c required that the remainder of the CEA's in the group be placed at either the fully inserted or fully withdrawn position. The licensee noted that the restrictions precluded CEA symmetry testing for the shutdown group which included CEA 44 because it would require the CEA's to remain at the full out position. CEA symmetry checks are used to verify the CEA is coupled to its drive mechanism and, therefore, capable of controlling reactivity. The licensee discussed their proposed course of action with the inspectors and the NRR Project Manager. The licensee proposed entering T.S. 3.0.3, the action requirements for conditions which are in excess of those specified in the individual LCO's and their associated action statements, by moving the CEA's in the affected group from their full out position one at a time as necessary to verify required reactivity effects. The duration would be approximately eight minutes for each CEA in the shutdown group. The total time involved would be less than one hour. During testing for CEA 44 the licensee stated that a visicorder trace would be maintained and observed to provide a positive indication of the CEA stepping motion (in addition to the CEA pulse counting channel). The NRC agreed that the actions proposed were acceptable and in accordance with the Safety Evaluations supporting Amendments Nos. 48 and 54. The inspector observed the CEA symmetry checks and visicorder traces for CEA 44. A literal problem remains with the surveillance requirements for Technical Specification 3.1.3.1 in that motion of the shutdown CEA group is still required every 31 days to verify that CEA's not fully inserted are operable. This is precluded by the requirement to maintain CEA's in the affected group at full out. The licensee stated that a change would be requested to preclude repeated use of T.S. 3.0.3 in order to satisfy surveillance requirements. This action will be followed by the NRC (318/83-02-03).

The inspector noted several problems during the performance of the non-overlap CEA integral rod worth measurements performed pursuant to PSTP-2 on 1/15/83. This portion of the startup test program basically consisted of starting in a critical low power configuration with essentially all CEA's out and initiating a constant dilution. Sequential insertion of the regulating group CEA's is used to balance the reactivity, a condition which results in a situation where the TS Special Test Exception (STE) 3/4.10, suspending the Shutdown Margin requirements of TS 3.1.1.1 must be invoked. The STE requires as an LCO that the Shutdown Margin equivalent to at least the highest worth CEA be available for trip insertion. Boration at 40 gpm is the required ACTION if the Shutdown Margin requirement is not satisfied. The inspector questioned operators and Nuclear Fuel Management (NFM) personnel concerning these requirements and at what point in time boration would be required. The operators were not aware they were entering the STE and stated they relied on the NFM personnel and the PSTP to satisfy physics requirements. The surveillance requirements for the STE state that the position of each full length CEA required either partially or fully withdrawn shall be determined at least once per two hours; and that each CEA not fully inserted be demonstrated capable of full insertion when tripped from at least the 50% withdrawn position within 24 hours prior to reducing the Shutdown Margin to less than the limits of TS 3.1.1.1. PSTP-2 directed that a reactor trip be performed prior to inserting group 1 CEA's, condition which satisfied the surveillance for CEA insertion capability provided a restart was performed within 24 hours of the trip. (The restart was the next step in the procedure, although the operators and NFM personnel were not aware that the trip was satisfying a surveillance requirement).

Following the questions by the inspector, the NFM Test Supervisor researched records on site and produced a Combustion Engineering to BG&E letter dated 12/23/82, Unit 2 Cycle 5 Startup Test Predictions and Core Data. This data verified that Shutdown Margin requirements were satisfied with Shutdown Banks and Group 1 withdrawn and provided a boration curve for a one stuck rod situation. The NFM-Test Engineer stated boration would be continued until the curve was satisfied if a stuck rod was encountered during the time that the STE was invoked. The procedure did not address the surveillance requirement to verify CEA position indication every two hours, nor were shift personnel preparing to conduct such a verification. The process computer Rod Group Log was initialized, which would result in the computer Data Logger typing CEA positions on an hourly basis, however, personnel do not routinely review this output to verify position information on an hourly basis. The procedure stated that such a verification would be performed during the time period when the STE was invoked. A change (PSTP2, Revision 4, Change 10) was approved by the POSRC on 2/4/83 to require verification of CEA positions prior to invoking STE 3/4.10 and at two hour intervals. The inspector reviewed

the training curriculum which had been presented to NFM personnel (a four day training session had been conducted for the Startup Testing Program) and concluded that additional training in this area was necessary for Operations personnel. The licensee committed to train Operations personnel in the Startup Physics testing procedures prior to the startup following the next refueling outage. This item is unresolved (318/83-02-07) and its completion will be followed by the NRC.

#### 11. Auxiliary Feedwater

At 10:30 a.m. on 1/12/83, while Unit 2 was in Mode 3 operation, an air line supplying instrument air to Auxiliary Feedwater (AFW) System valves AFW-4511 and 4512 became disconnected, and the valves failed open. AFW-4511 and 4512 are valves which regulate steam driven AFW pump flow to each of the Steam Generators (SG's). At the time of occurrence, the AFW system was supplying feedwater to the SG's and Operations personnel restored proper flow by reducing AFW pump turbine speed.

The air line failed at a compression type fitting located in the Unit 2 27 foot elevation East Piping Penetration Room. (The fitting had been installed during a recent AFW system modification.) The fitting had not been assembled properly. The inspector discussed the failure with licensee personnel and asked the licensee if the proper type of fitting was being used in the tubing assembly (the tubing must meet seismic requirements). He also asked the licensee to provide assurance that similar fittings in other (AFW associated) modified tubing sections were properly assembled. On 2/3/83 the licensee presented the following information to the inspector:

- (1) The type of compression fitting used in the AFW air system is approved for safety-related installation and meets ASME Code requirements for small line sizes;
- (2) The fittings were specified and purchased as safety-related items;
- (3) The use of the fitting had been justified by engineering evaluation which considered the transmitted loads to system components, the relative mass of system components, the shear forces present during a seismic event, and the forces expected to fail components;
- (4) Approximately 50% of the work step items involving installation of compression fittings were provided with QC coverage;
- (5) Each mechanical joint was pressure tested using a soap bubble solution; and
- (6) Only this one fitting failed representing a failure rate of only 0.1%.

The AFW system was modified during the 10/82-1/83 refueling outage, and a three minute time delay on pump start, following a low SG level condition had been removed. Additionally, the AFW system was modified to include a function for automatic isolation of a ruptured SG. That automatic isolation function had not yet been armed when the air failure occurred. (The licensee was awaiting approval of revised Technical Specifications associated with the modified AFW system.) A revised Main Steam Line Break (MSLB) accident analysis, incorporating the AFW system design changes, had been completed but was not applicable with the automatic SG isolation function inoperable. The previously existing MSLB accident analysis was not applicable because it assumed the three minute time delay on AFW actuation. Therefore, the licensee concluded that the interim AFW system configuration had not been properly considered in a MSLB accident analysis, and a prompt Licensee Event Report was initiated on 1/13/83.

The automatic SG isolation function was subsequently armed, making the revised MSLB safety analysis applicable.

The inspector reviewed the following references: (a) CCNPP Updated FSAR Sections 14.14 and 14.20; (b) BG&E (A. E. Lundvall) to NRC (R. A. Clark) ltr. dated 5/21/80 regarding Automatic Initiation of Auxiliary Feedwater; (c) BG&E (A. E. Lundvall) to NRC (B. H. Grier) ltr. dated 2/12/80 regarding Analysis of Steam Line Break with Continued Feedwater (Reply to IEB-80-04); and (d) BG&E (A. E. Lundvall) to NRC (R. A. Clark) ltr. dated 11/17/82, "Supplement 1 to Fifth Cycle License Application" (Unit 2).

Those references contain summary information of "Main Steam Line Break (MSLB) Inside Containment" safety analyses performed for Calvert Cliffs. All analyses assume delayed starting of the Auxiliary Feedwater (AFW) System following a MSLB. In the present Unit 1 AFW system configuration, the analyses assume a three minute time delay from event initiation to automatic AFW initiation. In the modified Unit 2 AFW system configuration, the analyses assume time delays for automatic actuation of 20.6 seconds for steam driven AFW pump flow and 52.4 seconds for motor driven pump flow from event initiation (at Hot-Zero Power Conditions with Loss of AC Power). In no case do the analyses assume the AFW system is operating and feeding water to the Steam Generators when a MSLB event occurs.

In practice, the licensee uses the AFW system to supply feedwater during plant startups when water in the Main Feedwater/Condensate System does not meet desired chemistry specifications. Recently, the AFW system was used to supply feedwater during low power physics testing of Unit 2 at hot-zero-power (1/11 to 1/14/83). This periodic use of AFW during non-transient plant conditions is a concern because it represents operation of the plant(s) in a potentially unanalyzed configuration. If a MSLB were to occur with the AFW system feeding the Steam Generators, the resulting Return-to-Power (R.T.P.) and Containment peak pressure are unknown.

The inspector discussed the above concern with the Plant Superintendent who agreed to further examine the problem. On 1/28/83, the Plant Superintendent informed the inspector that a reanalysis of the MSLB accident was being conducted which would include operation of the AFW system as an initial condition. Licensee completion of this reanalysis is unresolved (317/83-02-01).

Another modification to the Unit 2 AFW system accomplished during the 10/82 refueling outage was the installation of a third train, motor driven, AFW pump. On 1/17/83, the inspector observed a performance test of the new pump which was conducted at 5% reactor power under Technical Support Procedure (TSP) 99, Revision 0, approved 12/13/82. The test involved using the motor driven pump to supply feedwater to the #22 SG at various feed rates in both manual and automatic operation. Of particular interest was the system's ability to control flow to each SG at 160 gallons per minute (gpm). System performance was generally good but flow rate was not automatically controlled within the specified +/-10 gpm error band. Adjustments were made to the system's controllers. System flow control was described by the licensee as being much better than that observed during earlier tests conducted at lower SG pressures. The inspector expressed a concern about the system's exhibited instability in flow control at low SG pressures (low pump back pressure). At 0 psig SG pressure the pump experienced runout, and it was immediately stopped. At 50 psig the system exhibited large flow instabilities. These characteristics were attributed to the action of the Automatic Recirculation Control (ARC) valve (which actuates in a full open/full closed fashion to ensure minimum flow); and the fact that the air operated flow control valves were controlling near the closed position; and that control circuits had not been completely adjusted. The licensee committed to test the system's capability to operate for at least 10 minutes at the lowest SG pressure predicted to occur during a MSLB (about 500 psig). That test was to be conducted at the first cold shutdown when decay heat is available (318/83-02-04).

On 1/21/83, the inspector observed a test (also conducted under TSP 99) of the AFW system with both a steam driven pump and the motor driven pump simultaneously supplying feedwater to both SG's. The test was conducted at 55% reactor power. The system properly regulated AFW flow (average flow) through all four regulating valves at the specified 160 +/-10 gpm. The inspectors attended a Plant Operations and Safety Review Committee (POSRC) meeting on 1/21/83 regarding the AFW system. The POSRC determined that system performance was acceptable.

During the meeting the licensee noted that an approximate 55 inch difference existed between the narrow range (NR) SG level instrumentation and the newly installed wide range (WR) level instrumentation which actuates AFW (NR reading 55" lower than WR). On 1/24/83 the inspector noted that the same SG level indication difference existed at 100% reactor power and asked the licensee if the AFW actuation setpoint was within the limits specified in TS 3.3.2.1, "Engineered Safety Feature Actuation System Instrumentation". This TS requires that the AFW actuation setpoint be

between -194" and -149". The setpoint actually used was -170". The 55" indicated difference could cause system actuation as early as -115". A conference call was held on 1/24/83 involving licensee and NRC personnel. The licensee stated that a difference between WR and NR instrument readings had been expected prior to startup but that the magnitude of the difference was higher than expected. The precise reason was unknown. The licensee stated that the setpoint actually used (-170") was within the TS limits. The licensee stated that its NSSS vendor had conducted a safety analysis which showed acceptable results for both the MSLB and loss of feedwater accidents, (the accidents of concern), provided system actuation occurred between actual SG levels of -38" and -203". The licensee stated that they felt that the difference between WR and NR levels would not exceed 80". The above safety analysis was dependent on the value of the Moderator Temperature Coefficient and valid only for a limited length of time (approximately 1000 megawatt days/metric ton, or about one month). The licensee's evaluation supported the conclusion that, at least for a short period of time, early AFW actuation was bounded by safety analysis. The NRC asked the licensee to submit its safety analysis for review. The licensee also committed to develop and submit to the NRC a long term solution to the problem prior to the expiration of the 1000 MWD/metric ton period. On 2/3/83 the licensee informed the inspector that the above safety analysis had been determined to be valid for 3000 MWD/metric ton (or about 90 days).

Inspector review of the actual performance of the AFW Actuation System following Unit 2 trips (described in paragraph 4) indicated that the level mismatch (WR/NR) went away immediately following the trip and return to 0% power. The system design was also correct in the specification of an Actuation setting precluding actuations on "normal" reactor trips (SG water level had previously gone offscale low [ $\approx$ -116"] following reactor trips). Steam Generator levels, as measured by the WR instruments, decreased to about -130" following these trips. Resolution of the level mismatch problem will be followed by the NRC (318/83-02-05).

### 13. 10CFR21 Related Notification

About 12/6/82 the licensee and the NRC received a 10CFR21 related notification from the Capitol Pipe and Steel Co. regarding twenty-four fittings previously shipped to the licensee that had been magnetic particle tested to commercial levels only instead of in accordance with ASME Section III, Subsection NB. The licensee conducted a search for the fittings and found that one had been used in a non-safety related application. The remaining fittings were located in spare parts storage and were marked with QA Non-Conformance Report Hold Tags. The licensee informed the inspector of its actions. The inspector had no further questions.

#### 14. Pressurizer Spray Valves

On 2/3/82, while Unit 2 was in Mode 3 and testing was in progress on the Engineered Safety Features Actuation System, the inspector noted that, following a Containment Isolation (CIS) Actuation and the resulting isolation of Instrument Air to Containment, the Pressurizer Spray valves (RC-100E and 100F) shut and then began to drift open without operator action. Operations personnel had to stop the Reactor Coolant Pumps in Reactor Coolant Loop 21 to stop spray flow into the Pressurizer. CIS closes Instrument Air Isolation valve 2-CV-2085 (inside Containment). Valve 2-CV-2085 can then only be reopened by a local manual operation inside Containment. Closure of 2-CV-2085 shuts off Instrument Air to the spray valves which, according to Table 4-16 of the Updated FSAR, are designed to fail closed. As actually constructed, the spray valves are shut by spring force with air assist. The assist air is provided by small accumulators immediately upstream of the valve operators. Therefore, the valves should shut on loss of Instrument Air. For an unknown reason, perhaps due to incorrect spring adjustment or accumulator leakage, RC-100 E and F do not remain closed. Operations personnel told the inspector that this valve drift has been observed previously on both Units 1 and 2. Once the spray valves open, a Containment entry must be made to resupply Instrument Air to the valves. The inspector was concerned that the opening of RC-100E and F may introduce at least two operational problems following CIS actuations. The two problems stem from the fact that Pressurizer Auxiliary Spray ties into the normal Pressurizer Spray line downstream of valves RC 100 E and F. If RC-100E and F open with the Reactor Coolant System (RCS) in natural circulation, some or all of the Auxiliary Spray flow may divert back down the spray lines to the RCS cold legs instead of going to the Pressurizer. Auxiliary Spray flow to the Pressurizer is required by plant procedures for the following situations:

- (1) To cool the Pressurizer during RCS natural circulation cool down following a Small Break Loss of Coolant Accident (Abnormal Operating Procedure [AOP] 12, "Small Break Long Term Cooling", Revision 5 dated 5/7/82, Step B.3); and
- (2) To provide an alternate core flush path during long term natural circulation core cooling using the Emergency Core Cooling System ([AOP] 5, "ECCS Longterm Cooling Core Flush", Revision 5 dated 12/30/81).

The inspector discussed the above concerns with the General Supervisor-Operations (GSO) on 2/4 and 2/7/83. The GSO agreed to further investigate this item to see if corrective action is necessary. This item is unresolved (318/83-02-06).

15. Licensee Action on NUREG 0660, NRC Action Plan Developed as a Result of the TMI-2 Accident

The NRC's Region I Office has inspection responsibility for selected action plan items. These items have been broken down into numbered descriptions (enclosure 1 to NUREG 0737, Clarification of TMI Action Plan Items). Licensee letters containing commitments to the NRC were used as the basis for acceptability, along with NRC clarification letters and inspector judgment. The following items were reviewed.

- II.E.1.1.(1) Auxiliary Feedwater System Short Term Modifications (Additional Recommendation 2). During the Unit 2 Cycle 5 refueling outage (10/82-1/83) the licensee completed the installation of a third train, motor driven Auxiliary Feedwater pump and performed a 48-hour endurance test on that pump. A summary of test results was submitted to the NRC (R. Clark) in a letter dated 1/21/83. The summary results indicate that the pump tested satisfactorily. This item remains open as described in Inspection Report 50-317/81-21; 50-318/81-20.
- II.F.2.1.A Subcooled Margin Monitor (SMM). During the loss of #22 Vital AC Bus on 2/2/83 (see paragraph 4), the inspector observed that both SMM's were deenergized. The inspector discussed this with the licensee. Investigation and review of drawings (6750-M-346-116-4, Wiring Drawing for Panel 2C06) confirmed that both SMM's were powered from #22 Vital Bus. The inspector reviewed the requirements of NUREG 0578 and the NRC's October 30, 1979 clarification letter. This guidance requires redundant temperature and pressure inputs; displays; and calculators. Although the licensee does have (two total) redundant sensors displays and calculators, supplying power to these instruments from the same vital bus is not desirable. The licensee stated that they would investigate changing the power supply arrangement. This is unresolved (318/83-02-01).

16. Review of Periodic and Special Reports

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

- December 1982 Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated January 14, 1983.



-- January 3, 1983 Report of Changes, Tests and Experiments for Calvert Cliffs Units 1 and 2.

No unacceptable conditions were identified.

17. Unresolved Items

Unresolved items require more information to determine their acceptability and are discussed in Details 4, 8, 10, 11, 14, and 15.

18. Exit Interview

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