U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/Report: 50-317/85-30 License: DPR-53
50-318/85-32 DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: November 5 - December 10, 1985

Inspectors: for T. C. Elsasser 1/13/86
T. Foley, Senior Resident Inspector Date

for T. C. Elsasser 1/13/86
D. C. Trimble, Resident Inspector Date

Approved: T. C. Elsasser 1/13/86
T. C. Elsasser, Chief, Reactor Projects Section 3C Date

Summary: November 5 - December 10, 1985: Inspection Report 50-317/85-30; 50-318/85-32

Areas Inspected: Routine resident inspection of the facility, power operation of Unit 1, and the continued refueling outage of Unit 2 areas defined in IE Manual Chapter 2515 and additional topics including (1) a technical meeting with the NRC Office of Nuclear Reactor Regulation regarding Main Steam Safety Valve Test Program and Valve Operability, (2) Engineered Safety Features inadvertent actuation, and (3) routine resident inspection of the Control Room, accessible parts of plant structures, plant operations, radiation protection, physical security, fire protection, plant operating records, maintenance, surveillance, radioactive effluent sampling program, open items, and reports to the NRC. Inspection hours totalled 210 hours.

Results: One significant concern regarding housekeeping within the Emergency Diesel Generator Rooms, with emphasis on the licensee's maintenance practices and the condition of Emergency Diesel Generators. The inspectors reviewed one licensee identified violation regarding a failure to follow procedures, and results of a licensee investigation regarding a thorough root cause determination of Main Steam Safety Valve setpoint problems.

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DETAILS

1. Persons Contacted

Within this report period, interviews and discussions were conducted with various licensee personnel, including reactor operators, maintenance and surveillance technicians and the licensee's management staff.

2. Summary of Facility Activities

Unit 1 continued power operations throughout this report period with minor reductions in power for surveillance testing and preventative maintenance.

Unit 2 remained in cold shut down throughout the period. This report commences with Unit 2 fourteen days into its cycle 6 refueling outage. Rubberizing the Component Cooling Heat Exchangers ahead of schedule significantly contributed to a decrease in the outage schedule. During Inservice Inspection of plant piping, significant erosion of the turbine cold reheat lines was identified at specific locations which added to the work load. Approximately 21 repairs were anticipated, however these repairs did not impact the critical path. Fuel shuffle was completed on day 17 of the outage. On day 27 the steam generator nozzle dams were removed utilizing only 9.9 man rem vice the 46 man rem utilized during the last outage. At the completion of the outage, the critical path was about one day ahead of schedule. During the heatup, however, reactor coolant pump 21A displayed evidence of a degraded seal. The licensee therefore cooled down and replaced the seal which extended the outage approximately one week (this extention is beyond this report period).

3. Licensee Action on Previous Inspection Findings

(Closed) Inspector Follow Item (317/25-15-67 and 318/25-15-67) Survey of Licensee's Response to Selected Safety Issues: Steam Binding of Auxiliary Feedwater (AFW) and Mispositioned Control Rods. These surveys were completed and documented in Inspection Reports 50-317/85-13, 50-318/85-11 (Section 4f.) and 50-317/85-15;50-318/85-13 (Section 4d.(2)).

(Closed) Inspector Follow Item (317/84-07-03) Overall Plant Management and Much Technical Assessment During Emergency Drills Continues to be Done in the Control Room rather than the Technical Support Center (TSC). This is contrary to the guidance in paragraph 1.3.i of NUREG 0696, Functional Criteria for Emergency Response Facilities. Since this item was identified, the licensee has made a conscientious effort to shift management of the plant and technical assessment to the TSC. They have generally found this to be helpful in dealing with the emergency condition.

(Closed) Inspector Follow Item (317/84-11-01) Replacement of Component Cooling Water and Service Water Heat Exchanger Channel Heads (components which had been severely affected by graphitic corrosion). These channel heads have been replaced on both units with heads manufactured with carbon steel. All have improved cathodic protection and are either coated with coal tar epoxy or have a rubber lining.

(Closed) Unresolved Item (317/83-31-06) Technical Specification (TS) 4.8.1.1.2.c.2, regarding Testing of Ability of Diesel Generators to Reject the Largest Load Without Tripping, to be Revised to Reflect Addition of the Motor Driven Auxiliary Feedwater Pump (now the largest single load). The inspector confirmed with the NRR Project Manager that the appropriate TS change is scheduled for issue on December 6, 1985.

(Closed) Inspector Follow Item (317/85-02-05) Reactor Trip Breaker (RTB) Surveillance Test Requires Upgrade to Include In-Cubicle Testing. Modifications have been made on both units to the Reactor Trip Breaker cabinets to allow in-cubicle testing of RTB under voltage trips (by means of locally mounted push buttons). Surveillance Test Procedures M-200-1, Revision 5 (Unit 1) and M-200-1, Revision 5 (Unit 2) have been modified to include in-cubicle under voltage trip testing by use of these local push buttons. All RTB's in the reactor trip paths for each unit now have new front frame assemblies with Mobile 28 grease.

4. Review of Plant Operations

a. Daily Inspection

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

No violations were identified.

b. System Alignment Inspection

Operating confirmation was made of selected piping system trains. Accessible valve positions and status were examined. Power supply and breaker alignment was checked. Visual inspection of major components were performed. Operability of instruments essential to system performance was assessed. The following systems were checked:

-- No. 11, 12, 21 Diesel Generator Air Start checked on November 25, 1985.

-- Diesel Generator Room Ventilation checked on November 29, 1985.

-- Unit 1 Component Cooling checked on November 29, 1985.

-- Unit 1 Containment Spray System checked on December 4, 1985.

No violations were identified.

c. Biweekly and Other Inspections

During plant tours, the inspector observed shift turnovers; boric acid tank samples and tank levels were compared to the Technical Specifications; and the use of radiation work permits and Health Physics procedures were reviewed. Area radiation and air monitor use and operational status was reviewed. Plant housekeeping and cleanliness were evaluated.

Main Steam Line Safety Valves (MSSV)

Section 11 of Inspection Report 317/85-28; 318/85-28 described problems the licensee has experienced with MSSV setpoint drift. It also describes actions that were being taken at the time to identify and correct the root cause of the problem.

Efforts to identify the cause continued throughout this inspection period. All MSSV's were disassembled and inspected in the presence of a vendor representative. Measurements were taken of disk holder to guide clearances, spindle run out, and blow down ring settings. An inspection of valve component surfaces was also conducted. The results of these inspections are as follows:

The minimum valve disk holder to guide clearances ranged from 9t (thousandths of an inch) to 18t. Originally the vendor had specified a minimum allowable clearance of 10t (only one valve, 2RV 4001, had a clearance below 10t). More recently, evidently due to a problem with MSSV's sticking in an open position (in facilities utilizing higher operating pressures and temperatures than found at Calvert Cliffs), the vendor is currently recommending a minimum clearance of 15t. Clearances on all valves were opened to at least 15t

Vendor recommended maximum spindle run out is 3t. As found run outs ranged from less than 3t to 29t. All run outs were restored to within the recommended 3t.

Significant amounts of a substance believed to be over heated hydraulic oil (Fryquel), the hydraulic fluid used to actuate the nearby main steam isolation valves, was found deposited in four valves. At least a very light film was found in all valves. The Fryquel could have entered through the spindle penetration or a vent port on top of the MSSV bodies. The material was generally soft and gritty when found in accumulations in such locations as the inside of the disk holder. To the inspectors, the material appeared harder (more difficult to remove) when it took the form of a film in locations such as the outside of the disk holder. All of the substance was removed.

The above conditions were assessed by the licensee and the vendor. None of these conditions appeared to be the root cause of the problems, principally because no single marginal condition appeared in all of the

MSSV's which experienced setpoint drift. Additionally, the vendor did not feel that any of these conditions were severe enough to significantly affect valve operation/setpoint.

Blowdown ring settings were also checked. None of the as found positions were believed by the vendor to affect the setpoint by more than 1% or yield a blowdown of more than 15% (an acceptable blowdown range).

Testing was completed on the two valves shipped to Wiley Laboratories. The hydroset used in setting the MSSV's during the April 1984 refueling outage and at the beginning of the current outage was tested at the vendor's facility and compared with a new hydroset at the Wiley Lab on the actual valves. Its results were found to compare favorably (in a conservative direction) with the new hydroset, thus ruling out the hydroset as a root cause. Changes in room ambient temperature and system temperature were found to have relatively little effect on valve setpoint as long as temperatures were allowed to stabilize for about 4 hours before testing. Those valves were returned to the plant, installed, and tested at operating reactor coolant/steam generator system temperatures and found to be within the specified allowable limits (using the new hydroset). All other MSSV's will be checked using the same hydroset.

The licensee did a limited inspection of the internals of selected Unit 1 (operating at 100% power) MSSV's by using a mirror/flashlight to look into the vent on top of the valve bodies. Some evidence of Fryquel was seen in those valves.

The licensee reviewed the affects of the as found setpoint configuration upon applicable accident analyses. In all cases, steam generator (S/G) pressure did not exceed 1100 psia, which is the maximum allowable S/G pressure (110% of design limit). A very preliminary calculation did show an increase in off site exposures if a relief valve stack open in conjunction with a S/G tube rupture accident. However, the doses would be well within 10CFR100 limits.

A meeting was held between the licensee and NRR on this issue. In that meeting the licensee concluded that: (1) the apparent setpoint changes were not explained by the as found condition of the valves; (2) the apparent setpoint changes may possibly be the result of measurement technique; (3) the rebuilt Unit 2 valves will perform as designed, (4) the Unit 1 valves will open, provide full capacity, and reset as designed; and (5) there are no safety implications on Unit 1.

The licensee committed to the following future actions: (1) enhance applicable procedures; (2) set valves at 530 degrees Fahrenheit Reactor Coolant System temperature vice 500 degrees Fahrenheit; (3) provide QC coverage while verifying setpoints; (4) independently reverify setpoints of four Unit 2 valves twelve hours after initial setting; (5) verify setpoints of four valves during the first outage after four months of operation on Unit 2; (6) verify the setpoints of all 16 Unit 1 valves during

the next shutdown, reset any valves outside the 1% range, and (if necessary to reset any valve) verify setpoint of valves during the first outage after 3 months of operation.

The NRC will continue to monitor licensee actions on the MSSV's under Inspection Follow Item 318/85-28-02.

Brush Holder Arm Assemblies on Emergency Diesel Generators

The inspectors received notification from the Region I office of a potential problem with the structural integrity of brush holder assemblies for Beloit AC generators (supplied in combination with Colt-Fairbanks Morse product line diesel engines). At one facility, a fatigue failure occurred in the area where the brush holder support shaft is mounted to a cross brace on the generator frame. Information on the failure was provided to the licensee. The licensee examined the brush holder support arrangements on a spare generator and confirmed that they have a different mounting arrangement which is not susceptible to the same kind of failure.

Component Cooling Water Inlet Valves

On December 4, 1985 the inspector noted that the manually operated Component Cooling Water (CCW) inlet valves (1-CC-261 and 1-CC-266) to the Unit 1 #11 and #12 Shutdown Cooling (SDC) heat exchangers were in a throttled open position instead of full open. The unit was operating at 100% power at the time. Following a design basis (Loss of Coolant Accident) accident, CCW provides the cooling medium, by means of the SDC heat exchangers, for removing heat from coolant being recirculated from/to Containment through the spray system. On 1-CC-261 a reference point apparently indicating the desired throttling position was shown as a line or mark scraped in the paint on the valve body. On 1-CC-266 a reference point was indicated by the word "throttlemark" written in felt tip pen on the valve body. The valve lineup in the Operating Instruction for CCW states only that the valve should be in a throttled position. Paragraph 9.2.3 of the Updated FSAR indicates that the full flow of a component cooling water pump (5000 gpm or 2.4E6 lb/hr) is assumed to be provided to the shell side of each SDC heat exchanger. Since throttling of the inlet valves would reduce CCW flow to the SDC heat exchangers, the inspector recommended that the licensee confirm the validity of the throttle position markings and verify that sufficient flow, for appropriate design basis accidents, would be provided to the heat exchangers.

The inspector also recommended that, once verified, the labeling of the throttle positions be improved or the valve lineup be improved to more specifically describe proper valve position. The General Supervisor Operations stated he would confirm that these valves were being properly positioned and would take steps to improve labeling and/or the valve lineup. Subsequently, the licensee conducted a test to determine the CCW flow being provided to the SDC heat exchangers.

Preliminary calculations indicated that this flow was sufficient. Confirmatory calculations were planned. Completion of the calculations and improved labeling/valve lineup will be followed by the NRC (50-317/85-30-02).

No violations were identified.

5. Events Requiring NRC Notification

The circumstances surrounding the following event requiring prompt NRC notification pursuant to 10 CFR 50.72 was reviewed. For those events resulting in a plant trip, the inspectors reviewed plant parameters, chart recorders, logs, computer printouts and discussed the event with cognizant licensee personnel to ascertain that the cause of the event had been thoroughly investigated; identified, reviewed, corrected and reported as required.

Unit 2 ESF Actuation

On November 11, during a re-energization of sensor logic cabinet ZB an Emergency Safeguards Actuation took place. No water was injected into the core since the unit was in cold shutdown with the emergency safeguards pumps locked out as required by the condition of the plant (Mode 6). Investigation of the cause determined that the cabinet ZB was previously de-energized for maintenance on the turbine trip module. After completion of maintenance, operators were requested to restore power to the cabinet. This was done in accordance with OI-34 "Engineering Safety Features Actuation System", Section VI "Returning an Actuation Logic Cabinet to Operation with Normal Pressurizer Pressure and Normal Steam Generator Level".

However, pressurizer pressure was below normal pressure (Mode 6). Step B of the same section provides a conspicuous, totally obvious caution stating:

CAUTION

"If low pressurizer pressure or low steam generator pressure conditions exist the cabinet must be re-energized per Section IX."

Section IX "Returning Actuation Logic Cabinets to Operation During Low Pressurizer Pressure and Low Steam Generator Pressure Conditions" provides the correct procedure for the conditions present to re-energize the cabinet. Discussions with the General Supervisor Operations (GSO) indicated that operators had failed to follow this procedure at least once before, hence the conspicuous caution. To attempt to avoid future recurrence of this type of event the GSO (1) counselled the operator involved and discussed this event with all licensed operators and Instrument and Control technicians, and (2) committed to commence a review of those operation procedures to determine

whether a senior licensed person should be required to be present during the performance of those procedures which have in the past or are likely to cause a plant trip or safeguards actuation.

The licensee identified, reported and has initiated corrective action regarding this failure to follow procedures. The NRC enforcement policy does not generally excuse personnel errors. However, based upon the licensee's past SALP performance, cooperation with NRC, and relatively few occurrences of this nature, this is unresolved pending completion of the corrective action and review for personnel errors in the future (50-318/85-32-02).

Pressurizer Code Safety

During surveillance testing, the setpoint for Unit 2 pressurizer code safety valve 2-RC-201-RV was found to be out of its allowed tolerance (required setpoint is 2565 psia +/-1%; as found setpoint was 2619 psia). The setpoint was immediately restored to within specified tolerance.

Previously, there have been no similar events on Unit 2 and one similar event on Unit 1. This event does not appear related to the Main Steam Safety Valve drift problems described in section 3 of this report in that (1) the pressurizer valves are of a different design, (2) there is no significant history of previous problems on Unit 2, and (3) a different hydroset is used in testing the pressurizer valves. The hydroset used to test the pressurizer safety valves was sent to the vendor and found to be properly calibrated. The NSSS vendor analyzed applicable design basis events with the "as found" setpoint and preliminarily found no unacceptable safety consequences. The setpoint was rechecked during the Unit 2 heatup following the refueling outage and found to be satisfactory.

No violations 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, vehicle searches and personnel identification, access control, badging, and compensatory measures when required.

No violations were identified.

7. Review of Licensee Event Reports (LERs)

LERs submitted to NRC:RI for review 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 LERs were reviewed.

LER No.	Event Date	Report Date	Subject
Unit 2			
85-09	10/15/85	11/14/85	Blockage of Saltwater Flow to Service Water Heat Exchanger #21.
85-13	11/11/85	12/05/35	Inadvertent Initiation of Engineered Safety Features during Mode 6.

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 activity was included.

-- Routine inspections of the Emergency Diesel Generator; room, system, subsystems and supporting auxiliaries have noted numerous minor maintenance problems which taken together could significantly degrade the emergency system. These problems are generic to all three emergency diesels. The symptoms include several lubricating oil leaks, exhaust manifold leaks, fuel oil leaks, jacket cooling water leaks, and possible leakage between internal systems, i.e. exhaust to jacket cooling. Leakage of fuel and lubricating oil is continuously found on the sides (outside) of the diesel, in the sump, on exhaust lines, embedded in lagging, and a thin film of oil appears to have been deposited on ALL equipment, components and walls, floor etc., within each EDG room.

Discussions with plant management have resulted in attempted clean ups of the area and inspections by the licensee. Additional tours by the resident inspectors noted oil soaked rags and solvents left in the diesel rooms from attempted clean ups. Repeatedly, the residents have noted rags in the oil sump and oil on the exhaust lines of the diesel.

The inspector discussed several concerns with the licensee: the immediate concern for fire protection within the area noting minor fires in previous years which have taken place in the EDG rooms which were immediately extinguished by operators assigned to standby the diesel when running. This operator, however, periodically leaves the room for various reasons. Additionally, during an ESF actuation, an operator would be busy performing many additional functions in addition to observing all three (3) diesels operating simultaneously. The licensee would have difficulty tolerating a fire within the EDG room in conjunction with other design basis problems.

The second concern was related to the long term operability of the diesels and potential for failure due to possible internal supporting system leakage, i.e. overheating due to air in the jacket cooling, or possible water leakage into the combustion chamber.

The third concern is the general condition of the diesels. All three appear (externally) very used/worn. They are not typical of other safety systems maintained by Baltimore Gas and Electric and are significantly below the standards for any emergency systems set by the nuclear industry.

The following is a list of identified outstanding deficiencies as evidenced by Maintenance Request tags on each diesel. Numerous oil leaks remain unidentified and periodically rags and/or cigarette butts are noted in the EDG rooms.

No. 11 Emergency Diesel Generator

MR Number	Problem
011700	Lube oil leak under exhaust manifold
011551	11 D/G SRW in/out lines need painting and lagging (paint blistered and chared)
010376	Leaking fuel oil discharge connection
010377	Fuel oil return No. 1 cyclinder leaking coupling
011548	Missing lagging on SRW cooler
006832	11 EDG drip tank pump will not discharge; drip tank is full

No. 12 Emergency Diesel Generator

010490	CO leak under exhaust manifold
010491	Oil leak from lube oil strainer
008971	Three-way valve oil leakage
004313	Excess Delta T indicated when running on 12 D/G Jacket Cooler
011556	12 D/G lube oil filter cap leak
011560	12 EDG jacket cooling pressure alarm comes in while engine is running
009138	Suspect exhaust gas leakage into Jacket Cooling System

004315	Same as 004313
009415	CO found in 12 EDG jacket cooling water
010493	Oil leaks from cyclinder; south cover 123 7910 12, north cover 89 10
010494	Oil leak from under exhaust manifold
011524	North and south sides of turbo charger needs to be lagged
011651	EDG 12 generator frame has black carbon-looking residue; determine what it is
011552	Problems related to SRW to 12 EDG
005089	Problems related to SRW to 12 EDG
003991	Problems related to SRW to 12 EDG

No. 21 Emergency Diesel Generator

001150	EDG 21 hand fuel oil pump leaks
007431	Problems with SRW to 21 EDG
011544	Problems with SRW to 21 EDG
003482	Problems with SRW to 21 EDG
011673	Jacket cooling pump oil leak

These problems have resulted in part, because of the licensee's verbatim compliance with the Technical Specifications. Technical Specifications (TS) at Calvert Cliffs were originally written such that compliance required demonstration of diesel generator starting almost daily. This demonstration is required after changes in any condition that could potentially affect diesel operability; for example, after surveillance of any system that interfaces with diesel starting, preventative maintenance on the diesels or on the subsystems, i.e., service water cooling heat exchangers, when regular maintenance or modifications are required and in addition to the regularly required TS surveillance for operability. The licensee is very dedicated to complying with regulation in this regard. This appears to have contributed to operating the diesel in a manner inconsistent with the original design of the diesel, that is the excessive starts have resulted in the apparent wear. The licensee has requested a change to the TSs which has been approved and should alleviate a portion of the existing conditions.

An additional cause contributing to the existing condition has been the lack of an installed spare diesel. This results in testing the other two diesels whenever the swing diesel is removed from service. Because of minimal redundancy for the emergency power source, (i.e., three diesel generators for two operating units) a high degree of confidence is required that each will be operable. Due to a lack of a spare installed diesel, no opportunity to overhaul or perform significant maintenance on any of these diesels is afforded unless at least one unit is shutdown, thus placing increased pressure on the maintenance department to minimize major maintenance. A significant failure of a diesel generator could cause either one or both units to be shutdown for an extended period for repair, or reinstallation of a possible new diesel. Because of the above dependence on a high degree of operability, it would appear that an equivalent degree of maintenance attention should be directed towards maintaining the emergency diesel generators.

A third contributing cause of these conditions is the performance of the maintenance department work practices. Management's tolerance of lower standards and complacency have resulted in acceptance of slowly deteriorating standards for conditions in the diesel generator rooms and within the intake structure. This lack of <u>effective</u> quality control or personnel who possess high standards of work practices have resulted in or contributed to (1) the unacceptable conditions associated with the Emergency Diesel Generator Safety System, (2) two recent plant trips caused by grounds on the DC bus, possibly resulting from work practices by Instrument and Control technicians on the feedwater level circuits, and (3) improper rebuilding of Reactor Coolant Pump seals (Inspection Report 317/85-26) which may have contributed the one week extension of the Unit 2 Cycle 6 refueling outage due to Reactor Coolant Pump seal failures shortly after installation.

The aforementioned conditions of the diesel generator rooms and maintenance work practices appear to represent negative trends in the maintenance area and may be used as examples during future licensee evaluations.

The inspectors recognize that the demonstrated reliability of the Calvert Cliffs diesels is high, and that the licensee has in the past been very responsive to NRC identified concerns. Because of the licensee's demonstrated responsiveness and concern for the subject and to be in consonance with the NRC enforcement policy a violation is not issued, however, a response is requested. This item is considered unresolved (50-317/85-30-01; 50/318/85-32-01).

No violations were identified.

9. <u>Surveillance</u>

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 0-5-1, Revision 29, Auxiliary Feedwater System observed on November 26, 1985.

-- STP 0-4-2, Revision 13, Integrated Safety Features Test observed on November 29, 1985.

During the performance of STP 0-5-1, Auxiliary Feedwater (AFW) System, on Unit 1 on November 26, 1985, the inspector noted that the operator had to add oil twice (via the globe reservoir) over a half hour period to the inboard pump bearing of No. 11 AFW pump. The inspector noted this to the Procedure Development and Evaluation Supervisor, who is responsible for the operations surveillance test program, for further investigation (e.g. possible oil leakage). The STP exercises the governors of the steam driven pumps using both the Control Room and the local pump speed controllers. The inspector noted that speed control via the remote shutdown panel controllers is not, however, checked (requires shifting of local transfer valves). Since the remote shutdown panel AFW controllers are apparently not periodically exercised by another means or test, the inspector recommended to the above supervisor that such a check be considered for inclusion in STP 0-5. The supervisor agreed to evaluate this.

No violations were identified.

10. Adequacy of Emergency Procedures for ATWS Events

The Interim Reliability Evaluation Program (IREP) Analysis conducted for Calvert Cliffs, NUREG/CR-3511, lists ATWS (anticipated transient without scram) as one of the dominant accident sequences. Rapid operator action to manually scram the reactor and/or initiate emergency boration could reduce the primary pressure transient and thereby mitigate this sequence. The inspector reviewed two of the licensee's new Emergency Operating Procedures (EOP's), EOP 800 (Functional Recovery Procedure) and EOP 000 (Post Trip Immediate Actions), to confirm that appropriate operator action is specified. These EOP's are scheduled for implementation on January 1, 1986. Both procedures call for the operator to verify proper "reactivity control" (ensure Control Element Assemblies properly inserted into the reactor core). If automatic scram did not occur, these procedures direct: (1) manual trip of the reactor using manual reactor trip push buttons, (2) de-energization of the control element drive motor MG set feeder and tie breakers (can be done from Control Room), and (3) emergency boration (direct boric acid feed to the charging pumps).

No procedural inadequacies were identified.

11. Radiological Controls

Radiological controls were observed on a routine basis during the reporting period. Standard industry radiological work practices, conformance to radiological control procedures and 10CFR Part 20 requirements were observed. Independent surveys of radiological boundaries and random surveys of non-radiological points throughout the facility were taken by the inspector.

No violations were identified.

12. Unresolved Items

Unresolved items require more information to determine their acceptability and are discussed in Details 5 and 8.

13. 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.