U.S. NUCLEAR REGULATORY COMMISSION

REGION I

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE

BALTIMORE GAS AND ELECTRIC COMPANY

CALVERT CLIFFS UNIT 1 AND UNIT 2

DECEMBER 12, 1983

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I. INTRODUCTION

1.1 Purpose and Overview

The Systematic Assessment of Licensee Performance (SALP) is an integrated NRC staff effort to collect NRC staff observations annually and evaluate licensee performance based on those observations with the objectives of improving the NRC Regulatory Program and Licensee performance.

This SALP period is October 1, 1982 through September 30, 1983. This assessment also contains significant information which occurred prior to the assessment period where it has a bearing on the findings.

Evaluation criteria used are discussed in Section III below. Each criterion was applied using "Attributes for Assessment of Licensee Performance" contained in NRC Manual Chapter 0516.

1.2 SALP Board Members

Board

R. W. Starostecki, Director, Division of Project and Resident Programs (DPRP)
E. G. Greenman, Chief, Reactor Projects Branch No. 1, DPRP
R. R. Bellamy, Chief, Radiological Protection Branch, DETP
D. H. Jaffe, Project Manager, Operating Reactors Branch #3, NRR
R. E. Architzel, Senior Resident Inspector, Calvert Cliffs
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Attendees

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1.3 Background

(a) Licensee Activities

Unit 1

At the beginning of the assessment period (October 1, 1982) Unit 1 was operating at 100% power. On November 9 the reactor tripped on low steam generator level due to a power loss to the feedwater regulating valves following the loss of #11 vital AC Bus. Full power operation was resumed then followed by several power decreases to investigate saltwater leakage into the main condenser. On December 8 the unit tripped when an undervoltage condition occurred on the reactor trip bus. Full power operation resumed on December 9. On December 29 the unit was taken off line for one day for Reactor Coolant Pump maintenance. On January 5, 1983, an ESFAS initiation due to a short in the Containment High Radiation Monitor tripped the unit. On January 26, 1983, the reactor tripped on low steam generator level when feed pump speed control power was lost.

The unit was restarted and operated at 100% power until February 28, 1983, when a Moisture Separator Reheater level switch was bumped causing a reactor/turbine trip. The unit was returned to power, and power operation continued until it was taken off line on April 23, 1983 to repair a cracked weld on 11A reactor Coolant Pump controlled bleed-off line.

Power operations resumed on April 28. Unit 1 tripped on June 6, 1983, due to failure of 11A Reactor Coolant Pump Motor Surge Suppressor; power operation resumed and continued until August 27, 1983, when Unit 1 was taken off line to investigate a low indicated oil level in 12A Reactor Coolant Pump Motor. During restart the reactor tripped due to High Axial Shape Index. Power operation resumed. On August 31, 1983, the unit was manually tripped due to a reduction of Main Circulating Water flow caused by impingement of a large number of fish on the Traveling Screens.

On September 1, the reactor was restarted. On September 19 the reactor was manually tripped due to the reduction of Main Circulating Water flow caused by fish impingement. On September 30, 1983, a shutdown commenced for the sixth scheduled refueling outage. The total number of unplanned shutdowns occurring during this assessment period was twelve.

Unit 2

At the beginning of the assessment period (October 1, 1982) Unit 2 was operating at full power with periodic power decreases to investigate condenser saltwater leakage. The unit was taken off line on October 16 for its fourth refueling outage.

Unit 2 completed refueling on January 14, 1983, and commenced escalation to power. The reactor tripped on January 31 following the loss of #22 120 VAC vital bus. Unit 2 resumed full power operation and continued operating until March 6 when a loss of a 120 VAC vital bus caused a turbine/reactor trip. The unit was restarted and operated until May 15 when it was shutdown to check the oil level for #22A Reactor Coolant Pump. Power operations resumed.

Unit 2 continued power operation until the reactor was manually tripped on August 9, 1983 in response to increasing primary temperature when the Main Turbine Governor Valves spuriously started closing. Operation resumed. The reactor was again manually tripped due to turbine valve closure on August 22. On August 24 the reactor tripped on high Reactor Coolant System pressure when the Main Turbine Governor Valves and Intercept Valves rapidly closed during troubleshooting. On August 31 a shutdown was commenced due to a concern that feedwater flow would not adequately reduce following a reactor trip. During the shutdown the reactor tripped on Low Steam Generator level from 25% power following the loss of the only operating feed pump.

Unit 2 resumed full load operation on September 2, 1983, until it was taken off line to replace a leaking pressurizer manway gasket on September 17, 1983. Full power operation resumed. The total number of unplanned shutdowns occurring during this assessment period was eight. At the end of the assessment period Unit 2 was operating at full power.

(b) NRC Inspection Activities

Two NRC resident inspectors were assigned during the assessment period. The total NRC inspection hours for the period was 2785 (resident and region based), with a distribution of effort in the functional areas as shown in Table 2.

NRC inspections and violations identified during the period are tabulated in Tables 3 and 4.

II. SUMMARY OF RESULTS

CALVERT CLIFFS NUCLEAR POWER PLANT

FUNCTIONAL AREA	CATEGORY 1	CATEGORY 2	CATEGORY 3
1. Plant Operations		X	
2. Radiological Controls		X	
3. Maintenance			X
4. Surveillance (Including Inservice Testing)			X
5. Fire Protection and Housekeeping	X		
6. Emergency Preparedness		X	
7. Security and Safeguards	X		
8. Refueling		X	
9. Licensing Activities		X	

Overall Summary

This the the fourth assessment of licensee performance by the NRC staff under the Systematic Assessment of License Performance program. It contains an assessment of licensed activities for normal operations, plant events and outage activities.

In general the licensee's performance in each of the functional areas evaluated was acceptable and demonstrated a regard for regulatory requirements.

Noteworthy performance characterized by well planned and implemented programs was identified in the Fire Protection/Housekeeping and Security and Safeguards areas.

Continued management attention is needed to the following areas: reduction of personnel errors with emphasis in the maintenance and surveillance areas, assessment of adequacy of maintenance and surveillance procedures, training of operators on necessary support systems, document control, the review/safety evaluation of maintenance activities, control of plant changes that require prior Technical Specification changes, and the review of proposed Technical Specification changes (to ensure they will achieve desired results in correcting operational problems).

III. CRITERIA

The following criteria were used, as applicable, to evaluate each area:

1. Management involvement in assuring quality.
2. Resolution of technical issues from a safety standpoint.
3. Responsiveness to NRC initiatives.
4. Enforcement history.
5. Reporting and analysis of reportable events.
6. Staffing (including management).
7. Training effectiveness and qualification.

To provide a consistent evaluation, attributes relating each aspect to Category 1, 2, and 3 performance characteristics were applied as discussed in NRC Manual Chapter 0516, Part II and Table I.

The SALP Board conclusions were categorized as follows:

Category 1: Reduced NRC attention may be appropriate. Licensee management attention and involvement are aggressive and oriented toward nuclear safety; licensee resources are ample and effectively used such that a high level of performance with respect to operational safety is being achieved.

Category 2: NRC attention should be maintained at normal levels. Licensee management attention and involvement are evident and concerned with nuclear safety; licensee resources are adequate and reasonably effective such that satisfactory performance with respect to operational safety is being achieved.

Category 3: Both NRC and licensee attention should be increased. Licensee management attention or involvement is acceptable and considers nuclear safety, but weaknesses are evident; licensee resources appear strained or not effectively used such that minimally satisfactory performance with respect to operational safety is being achieved.

IV. PERFORMANCE ANALYSIS

1. Plant Operations (37%)

The analysis of this area includes plant operational activities, as well as operational support activities. During the assessment period the operations area was routinely reviewed by the resident inspectors. Inspections performed encompassed the following areas: commitment to safe plant operations, compliance with license and procedural requirements, event followup, committee activities, corrective action programs, reporting systems, and staffing. The Quality Assurance organization and implementation, including audits, inspections and surveillances were examined by Regional Inspectors.

The previous SALP determined operations to be Category 2. Overall, operations was considered strong and improving with deficient areas receiving attention. The most significant problem area was operating staff stability and experience. The SALP recommendation was to continue to emphasize licensed operator staffing, the task force effort on piping systems, and operator awareness of equipment and corrective action status.

The conservative attitude towards safe plant operations and cooperation when addressing NRC concerns noted during the last SALP period continued. A particular strength of the licensee is the overall positive attitude on the part of plant staff personnel towards their work. The plant staff also maintains a high morale and are by and large proud of their work and qualifications, as evidenced by low personnel turnover and good housekeeping.

Operator errors caused a total of four operational events during the assessment period.

Operators have responded in a proper fashion to operational events during the evaluation period. This has been noted by inspector observations and post event reviews. The operators have been knowledgeable of and followed plant operating and emergency procedures resulting in rapid placement of the plant in stable conditions. Examples of these events include plant trips due to loss of circulating water pumps, inadvertant containment spray actuations, reactor trips from full power caused by Electro Hydraulic Control malfunctions, several other inadvertent Engineered Safety Features Actuations, and unit trips caused by malfunctions in the Main Feedwater System.

No deficiencies have been noted in the reporting of operational events. Operators have been diligent in recognizing and documentation of entry into Technical Specification Action Statements and their expiration times. This practice contributes to awareness of plant conditions and ensures adherence to regulatory requirements. The AEOD (Office for Analysis and Evaluation of Operating Data) review of Licensee Event Reports found that the licensee's reports were informative, understandable and, as a package, they consistently met or exceeded the guidelines offered in NUREG-0161. The LERs were found to be detailed so an informed assessment of safety and potential consequences could be made by someone reasonably familiar with the plant. Refer to Section V.b for further detail.

Prior to the Salem ATWS (Anticipated Transient Without Scram) event, the licensee conducted post-trip reviews following unscheduled reactor trips. In March 1983, the resident inspector reviewed the licensee's practices in this area and made several recommendations for improvement based on lessons learned from the Salem event. The Plant Manager was receptive to these recommendations and, in fact, was already implementing one recommendation (developing a formal procedure describing current practices). Further program upgrades were initiated in response to these recommendations.

The licensee's procedures for required actions following a plant trip was reviewed twice during the evaluation period. The licensee was responsive in addressing NRC concerns which were raised following the ATWS (Anticipated Transient Without Scram) at the Salem Nuclear Power Station. The current post trip review procedures require thorough and timely review of these events and available data as evidenced by detailed procedure checklists.

In August 1983, during a post-trip review, the licensee noted an apparent slow feedwater system response time based on information from the Technical Support Center Computer (a relatively new information source that the licensee was using to upgrade its post-trip reviews). Further investigation showed that the computer generated response time was incorrect and that plant system response was proper. As a result of NRC concerns regarding why the excessive computer response time had not been noted during reviews for previous trips, the licensee, prior to plant restart, initiated additional post-trip review upgrades, and described their program in a presentation to NRC Region I management personnel on September 2, 1983.

The licensee has been successful at retaining and qualifying operators. As of November, 1983 sufficient qualified personnel were on hand to man six shifts. (Six shift supervisors, 12 senior control room operators, 28 control room operators and 60 plant operators were on hand. One shift supervisor, two senior control room operators, and three control room operators are required per shift for 2 units operating). In addition, two control room operators and eight plant operators had taken the NRC examination for senior and reactor operator, respectively, and were awaiting results.

Three control room operators were transferred to the Training Organization during the evaluation. The only additional loss of a licensed-individual was a senior control room operator who left operations after the evaluation period. The licensee plans to remain in a five shift rotation until 1985. This will have the effect of concentrating the experience of senior licensed operators on shift and allowing more time to develop experienced senior licensed operators. The licensee's approach appears to be a prudent course of action, although they do have the personnel available to implement a six shift rotation

The licensee has implemented a well staffed and comprehensive equipment (mechanical) safety tagging program. Two operators are assigned full time during normal operations. During outages this complement has been increased to include 24 hour coverage by four operators. Electrical/ instrument tagging is still performed by the shop performing the actual work, however, the licensee plans to implement an Electrical/I&C Tagging Authority. An independent verification requirement has been belatedly instituted for Electrical/I&C tagging. The Valve Tagging/Print Verification Task Force has been continued throughout the evaluation period. Numerous Operating Instruction valve lineups have been revised to include valve nomenclature and locations. Stainless Steel metal tags identifying valve number, function, and if appropriate, locking status have been placed in the field. The OM drawings and Operating Instructions have been revised to include instrument valving and checked for accuracy with the as built configuration. This effort appears to be of substantial benefit in terms of operator/technician/other personnel knowledge of plant systems and valving function and should enhance operational safety in the coming years. The licensee plans to continue the task force following completion of initial verifications for maintenance purposes.

Several apparent design and/or early construction deficiencies were noted in several safety related systems, examples included:

-- Filter damper actuators in the ECCS pump room exhaust ventilation system were found to be incorrectly installed.

-- The ECCS Pump Room Exhaust Fans' discharge dampers were only supplied with instrument air (no accumulator provided to ensure operability following a seismic event).

-- Only one, common accumulator was provided for the operation of Penetration Room dampers in redundant trains of the exhaust filtration system.

These ventilation system problems were identified by operations and maintenance personnel. These discoveries indicate an inquisitive attitude on the part of the individuals involved. After identification by a Shift Supervisor, the third problem was incorrectly evaluated by the Engineering Department as not constituting a problem because the accumulator was a passive device, not subject to active failure. Following this determination the accumulator air supply regulator (an active device) failed such that air pressure was lost and neither damper could operate, rendering both penetration room exhaust systems inoperable. The licensee now plans to install redundant accumulators and conduct additional checks of safety related ventilation systems for similar problems.

Another design/early construction deficiency identified by the NRC during the evaluation period was the location of ambient pressure sensors for the Chemical and Volume Control Isolation System in two physically separate rooms such that the actuation logic (2 of 4) would only have been satisfied if both sensors in a particular room functioned.

Inspector review of committee activities (Offsite Safety Review Committee, Plant Operations and Safety Review Committee, and the Plant Operational Experience Assessment Committee) and attendance at periodic and special meetings indicated that they were functioning in accordance with their charters and performing adequate reviews to ensure nuclear safety.

Combined inspections 317 and 318/83-10 reviewed the areas of QA audits, organization, and quality control inspections. No violations or unresolved items were identified during this inspection. There was a high degree of management involvement in QA activities. QA activities were well planned; were performed in accordance with administrative procedures; and QA activities were well documented in complete and available records.

The QA organization uses outside technical experts, in-house QA training and management emphasis to apply a continuing technical/safety review over plant operations. In addition, the QA organization has implemented an QA program for assuring compliance with NRC initiatives, including applying QA to radwaste and operational activities.

The QA organization is adequately staffed with qualified personnel including 55 persons onsite and 23 persons offsite. Training and qualification of QA personnel is thorough, well planned, and well documented.

During the evaluation period a training program for the engineer and technicial support staff (NPD Technical Support engineers, PMD engineers, nuclear engineers, and operational licensing, industrial safety, and fire protection personnel) was developed and implemented. The program was developed by training group personnel based upon position and task analyses. Group Principle Engineers have been assigned responsibility for training conduct utilizing training group and vendor resources. The licensee has continued its policy of providing operator licensing training to selected engineers.

One violation of 10CFR50.59 was identified. A Containment Isolation Valve for the Oxygen Sampling function (Reactor Coolant Drain Tank) had its mode of operation changed from automatic isolation and administrative controls to solely administrative controls without prior NRC approval. Another example identified during the evaluation period of a modification to the facility which affected the Technical Specifications was removal of a snubber on the Technical Specification list. These examples were initiated prior to the evaluation period however identified in the period. Licensee corrective actions appear to have resulted in a more disciplined approach to permanent facility changes which adheres to the intent and requirements of 10 CFR 50.59. Misinterpretation of the requirements of 10 CFR 50.59 as they apply to temporary modifications to the facility during maintenance contributed to the inoperability of the ECCS Pump Room Air Coolers (see Maintenance Section). This also lead to otherwise imprudent operating conditions, such as the opening of the watertight doors to both Unit 1 ECCS pump rooms to install a temporary hose rig between redundant Salt Water Systems.

Two additional violations were identified. Procedures were not followed when high out of specification boron concentrations were indicated (caused by bad reagents, not actual chemistry). This was caused by a poor shift turnover. A component cooling water valve to a High Pressure Safety Injection Pump was found mispositioned by the resident inspector. This raises a concern in that, although the licensee had a program in place which would have resulted in proper positioning upon startup from the next refueling, the mispositioning of the valve in question was found by the NRC and not licensee personnel.

Conclusion:

Category 2

Board Recommendations

Resident Inspectors should examine the handling of a technical issue by the Review Committees and one raised during the conduct of an audit.

The licensee should strive to ensure a more thorough understanding of the basis and requirements of the Technical Specifications and FSAR by operations and maintenance personnel, supervisors and review committees.

2. Radiological Controls (10%)

During the current period, five routine inspections were conducted onsite by Regional Health Physics Specialists, three in radiation protection and one of transportation and radioactive waste management. Portions of the effluent monitoring and control program were reviewed. The NRC Region I Mobile Laboratory was used to make radiological measurement intercomparisons during one inspection. The resident inspectors reviewed selected program areas throughout the period.

During the previous period, the licensee was determined to have had a Category 1 radiological controls program. Potential weaknesses identified in Radioactive Waste Management (operations) and the reliability of the Containment Atmosphere Particulate Monitor have continued through the present period. Overall, the program has shown a continued high level of performance in some areas, but growing weaknesses in others.

2.1 Radiation Protection

The radiation protection organization was well controlled during the period. The professional staff was expanded, and the technician staff was augmented enabling effective support to a major outage that included fuel rack replacement.

The technician training and qualification program clearly defines the qualification sequence and responsibilities. A training program for all radiation workers is well defined and implemented. A radiological controls discrepancy program provides management-monitored feedback for job conduct in these areas.

Radiation protection policies and procedures are well defined and widely distributed. Violations of procedures and procedural deficiencies were noted in respiratory protection and sealed source leak testing, but were promptly and effectively corrected.

Licensee performance in maintenance of internal and external exposure records results in accurate and complete documentation of exposures received by workers. Radiation surveys, contamination and air sample/records enable accurate preparation of radiation work permits.

The ALARA program is documented, adequately staffed and appears to be adequately implemented. A monthly summary of exposures and events is prepared for department and senior management information. An incident reporting system provides feedback about radiological practices and is included in the monthly summary. Radiation exposure administrative guidelines have helped focus management attention on program weaknesses, especially in view of the high exposure rate jobs which were performed during the Unit 2 outage.

The licensee's facilities, instrumentation and equipment were adequate to support radiological work.

Internal radiation protection audits, and those conducted by Quality Assurance were generally complete and thorough. Findings were answered and corrective actions were approved by senior management.

The licensee effectively used the Radiological Event Category of the Emergency Response Plan implementing procedures. This section was developed to allow use of a single procedure to investigate off normal radiological conditions. The Radiological Event category is reserved for those off normal conditions which do not meet the thresholds for an Unusual Event or higher emergency classification. The approach has allowed for rapid response by qualified personnel to allow assessment and evaluation of conditions. The system also provides excellent documentation of conditions and actions taken which eases the review process. Several Radiological Events responses have been observed by the resident inspectors in the evaluation interval and the records of many others reviewed. Licensee actions have been appropriate and thorough. None of the events which occurred during the evaluation period were of significant radiological concern.

The licensee had not implemented an effective control/evaluation system to address the effects of lead shielding on plant piping systems and structures. Following inspection of this area by the NRC, efforts which were being worked by the licensee were expedited and the scope of review expanded to ensure additional, unanalyzed shielding was not in place on plant systems.

2.2 Radioactive Waste Management and Transportation

The programs are staffed with qualified technicians. Technicians are included in the department training and qualification program. Licensee supervision has technical assistance from ALARA, chemistry, plant engineering and radiation safety management for the purpose of ensuring adequate supplies and maintenance of radiological equipment.

Radioactive waste management and transportation procedures at the end of the period were still under review by the licensee despite regulatory implementation dates of July and September 1983. Adequate progress appears to have been made for implementation of waste classification radioactive waste management procedures which become effective in December 1983. Transportation procedures are expected to be implemented by mid-November 1983. Waste housing and segregation is presently done in temporary facilities. The use of temporary facilities will be lessened when the solid waste facility presently being constructed is completed.

Licensee audits of the program have been generally complete, findings acknowledged and corrective actions taken.

During the evaluation period, the NRC discovered that the Reactor Coolant Waste Monitor and Receiver Tanks vacuum protection was jeopardized by the placement of poly sheeting over the tank vents, not withstanding an IE Bulletin addressing this concern and a response indicating that the tanks were protected by continuous vents.

2.3 Effluent Monitoring and Control

The licensee has an adequate organization for effluent monitoring and control. The staff appears to be qualified.

Weaknesses in the licensee's program included inadequate data review, violations of sampling procedures, insufficient judgment guidance for technicians in analytical procedures, and poor record maintenance. Management permits technician discretion in decision-making, but does not adequately review those decisions.

The licensee had been using a units translated limit for verification that the Group II (Iodine and Particulates with half-lives greater than eight days) airborne effluent release rate was less than the Technical Specification limit. Upon questioning by the NRC the licensee provided calculations which were to provide the basis for the translation, showing a conservative limit. NRC review indicated that the calculations were in error (using the lowest versus the highest Maximum Permissible Concentration), however, this error had not resulted in any releases greater than Technical Specification limits for over one year of data which was reviewed.

In-plant audits were generally complete. Findings were brought to management attention. Acceptable resolutions to audit findings were proposed, approved and implemented.

Conclusion

Category 2

Board Recommendation

Maintain routine inspection coverage with increased attention to supervisory involvement in radioactive waste shipment and effluent management and control.

3. Maintenance (9%)

Maintenance was reviewed during regular resident inspections.

The 1982 SALP Report concluded that maintenance was a Category 2 functional area. Significant weaknesses noted which have continued into this SALP evaluation period are a large number of maintenance induced plant trips/ Engineered Safety Features Actuations and insufficient priority given to the repair of plant equipment either not covered by Technical Specifications or the inoperability of which does not require plant shutdown.

The licensee is implementing three computerized information management systems for handling maintenance activities.

During the last SALP reporting period, maintenance induced a large number of Engineered Safety Features Actuation System (ESFAS) actuations and plant trips and other operational events. This problem has continued. In this reporting period maintenance and surveillance activities caused the following maintenance induced events or actuations of reactor protective systems and engineered safety features:

Unit	Date	Trip	Nature
2	11/10/82	ESF	Technician tried to terminate an ESFAS STP improperly and did not insert a low RCS system pressure block.
2	11/11/82	ESF	During performance of an ESFAS STP a procedure step directing insertion of a system low pressure block was obscured by a clip on the clipboard.
2	12/30/82	ESF	Operator deenergized ESFAS sensor cabinet ZG while cabinet ZF was tripped state for an STP.
2	1/07/83	Loss of Shutdown Cooling	Operator performing ESFAS STP (RAS) forgot test would stop LPSI pump (Shutdown Cooling).
2	1/12/83	ESF	Operator opened spray valve for a maintenance test, forgot new SIAS setpoint and sprayed RCS below actuation pressure setpoint.
1	11/09/82	RPS	Contractor bumped open inverter breaker while pulling cable. Lost power to MFW Reg. Valves. Plant trip on low steam generator level.

Unit	Date	Trip	Nature
1	12/08/82	RPS	During CEA withdrawals, all CEA's moved out simultaneously. Turbine/ Reactor trip on trip bus undervoltage (as a preventative maintenance action to minimize control rod wear all CEA's were partially inserted).
2	2/02/83	ESF	Inverter transfer switch terminal leads reversed.
2	2/03/83	RPS/ESF	During corrective maintenance operator deenergized wrong RPS cabinet.
1	2/28/83	RPS	Contractor bumped MSR level switch which caused turbine/reactor trip.
1	4/23/83	ESF	Following ESFAS maintenance operator used wrong procedure for reenergizing logic cabinet.
1	4/26/83	PORV Opening/ Inoperability	Operator raised RCS pressure too high and caused PORV to open. During subsequent corrective maintenance the second PORV was rendered inoperable.
2	8/11/83	ESF	Following ESFAS maintenance, ESF trip occurred during reenergization of ESF logic cabinet.
1	5/24/83	Loss of ECCS Pump Room Air Coolers	During maintenance, isolated salt water to both coolers.
1 & 2	8/10/83	Loss of DG #12	Following PM, technician failed to properly realign F.O. Day Tank Valv .

Operator and technician errors caused the major number of these events.

The Diesel Generator #12 event (Civil Penalty issued) pointed out weaknesses in: (1) implementation of independent verification requirements, (2) post maintenance testing, and (3) employee attention to detail. The ECCS pump room air cooler event (Civil Penalty issued) pointed out weaknesses in operator training on necessary support systems and review/safety evaluation cf safety related maintenance activities.

To reduce the number of personnel errors, the licensee established programs which increase employee awareness, upgraded employee training programs, improved error reporting and personnel counseling programs, and began evaluating and trending personnel errors. Reviews of planned maintenance and surveillance test procedures have been initiated to determine their adequacy. Improvements in the organization of the Instrument and Controls Group are planned. This includes the addition of new supervisory positions to reduce the span of control/responsibility of individual supervisors and enable them to spend more time in the field.

Insufficient priority has been given to correcting deficiencies in equipment described in the FSAR which provides additional reliability or information useful to operations personnel but yet does not directly affect plant operation. Examples include inoperable failed fuel monitors and an inoperable installed spare High Pressure Safety Injection Pump (deficiencies discussed in the two previous SALP Reports), inoperable boronometers on both units (discussed in last years SALP) and improperly insulated boric acid pump casings (a long standing problem that had been identified but not corrected). Additional prodding by the NRC during this evaluation period was necessary to initiate repair efforts. Because such equipment is part of the facility design it should be kept operable. A similar problem of insufficient management priority was evidenced by the licensee's generally slow response to various IE Notices and Bulletins and vendor recommendations regarding inspection, testing, and (if necessary) replacement of GE HFA relays.

During this reporting period, additional resources have been devoted to the staffing of a maintenance training organization and development of training programs. The Nuclear Power Department (NPD) added one supervisor and three technical training instructors to its Training Group (total of eight instructors devoted to Technical Training and General Orientation Training) and is seeking INPO accreditation of the Technical Training Programs. The Production Maintenance Department (PMD) created a new training group of three instructors to conduct onsite maintenance training unique to the Calvert Cliffs plant. PMD continues to draw on company training programs conducted offsite for generic mechanical maintenance training. Selected systems training was also provided to site maintenance personnel by the Nuclear Power Department. This effort, in conjunction with the steps identified previously, should be helpful in resolving personnel error problems.

The licensee improved its welding control program by establishing routine checks on welding machine current. Additional upgrades in the welding program are under development.

The structure of the QC role in the maintenance area should be reconsidered. In particular, effective QC coverage is evident in the corrective maintenance but lacking in preventive maintenance and surveillance.

Mockups (e.g. steam generator/primary side) were effectively used for training to ensure proper work performance, reduce work time and reduce radiation exposures.

Conclusion

Category 3

Board Recommendations

The NRC should verify licensee corrective actions to reduce personnel errors, assess adequacy of procedures, and train operators on necessary support systems within the next six months.

As noted above, the structure of the QC role in the maintenance area should be assessed.

4. Surveillance (11%)

During this inspection period the resident inspectors routinely reviewed and observed the licensee's surveillance activities. Two region-based inspections were conducted in the areas of Containment leak rate testing and the surveillance and calibration programs. The previous SALP evaluation of this area was category 1, with a determination that the program was effective overall.

During a region based inspection of the Surveillance Test Program, it was observed that the licensee demonstrated consistent evidence of good prior planning and assignment of priorities. All surveillance and calibration activities were planned and completed as scheduled; and there was no evidence of any missed surveillance tests.

The Plant Operations Safety Review Committee (PORSC) consistently meets and reviews all procedure changes; instances where acceptance criteria were not met during a test; and equipment malfunctions occurred during tests. POSRC and supervisory reviews of test were observed to have been accomplished in a thorough and timely manner. Records of complete surveillance and calibrations were well maintained, complete, and readily available.

Training and qualification of personnel performing tests is well defined and implemented. Individuals may only perform surveillance tests or calibrations for which they have been certified; however, an area of concern was identified in procedure adherence during the performance of surveillance tests. Recent occurrence of operator and technician error at the plant has prompted some additional inspection in this area. A level IV violation was identified during NRC observation during a test, an operator failed to open a valve as called for by a test procedure. Also, the test procedure did not properly restore a valve to the position as specified in a separate operating instruction.

The records of Local Leak Rate Testing (LLRT) and Integrated Leak Rate Testing (ILRT) were reviewed. These records were found to be generally complete, well maintained and available. The approach to the resolution of technical issues from a safety standpoint was satisfactory and understanding of issues by the involved personnel was generally apparent. This was demonstrated by the fact that the licensee was recording "as found" and "as left" leakage values for containment penetrations as part of the LLRT program. The need to add the difference between the two values to the "as left" value of the ILRT result to determine the "as found" value of the ILRT was understood by the licensee.

The interface between QA and surveillance testing was reviewed. It was observed that monthly surveillance test schedules were forwarded to the QC Surveillance Supervisor, from which tests for QC witnessing were selected. QC also performs 100% coverage of post maintenance tests associated with maintenance requests (not operability tests).

Several ESFAS actuations have been caused by technicians improperly performing or restoring conditions following surveillance tests. I&C technicians and operators have been sensitized to the importance of properly following surveillance test procedures. Additional comments regarding operator and technician errors leading to plant transients are contained in the Maintenance functional area section. A series of ESFAS actuations and unit trips occurred during the evaluation caused by a combination of equipment problems, operator and technician errors. The equipment problems were found to be an overly sensitive current limiting feature of the 120 Volt AC Vital Inverters, causing large voltage transients on the output (AC) side (essentially turning power off/on).

NRC review of Calibration of Power Range Nuclear Instrument testing by I&C technicians indicated a weakness in their understanding of: (1) the administrative requirements of changing Surveillance Procedures, (2) the functioning of the Rod Drop Circuitry, and (3) the proper actions to take upon discovery of a system malfunction.

The licensee tested the under voltage (UV) trip feature of the Reactor Protective System Trip Breakers as required by NRC Bulletin 83-04. The times were found to be in excess of design in many cases. Although the operation of the UV coils had been periodically verified in the past no response time testing was performed. A monthly test of the UV trip function was started.

During the reporting period the licensee identified that one snubber had been mislabled, hence another snubber had not been receiving proper surveillance testing. The licensee's initial actions only included a visual inspection of this snubber. Upon questioning of the adequacy of this action by the NRC the licensee agreed to functionally test both snubbers. The snubber which was not previously tested was found to be out-of-specification for both bleed rate and lockup.

A violation of surveillance testing requirements for the Electric Motor Driven Fire Pump was identified in that the pump was not run on recirculation flow. Of particular concern in this violation was the fact that the pump was dead-headed for 15 minutes and fire protection personnel did not recognize that a problem existed when the circulation relief valve failed to open.

Conclusion

Category 3

Board Recommendations

Licensee should objectively assess the need for increased supervisory involvement and consider programs to upgrade personal accountability to minimize personnel errors. This also applies to the maintenance area.

5. Fire Protection (4%)

One region-based inspection was conducted. The resident inspectors monitored this area throughout the period.

The 1982 SALP concluded that this was a category 1 functional area with no significant deficiencies. The licensee's fire protection program continues to be well implemented and maintained. An effective housekeeping program is evident.

The licensee improved its plant inspection program during this reporting period. Senior supervisors now inspect plant zones on a monthly basis. The Plant Superintendent has taken an active role in these inspections. Senior management personnel emphasized maintenance of good housekeeping and good equipment/material condition and have set ambitious goals for improvement in these areas.

A regional inspection of the Fire Protection/Prevention Program, administrative controls and procedures, Fire Brigade Training and audits, and implementation of Technical Specification maintenance/surveillance requirements found no significant problems or programmatic deficiencies. The licensee was responsive to NRC concerns in that there was a timely response to a potential NRC finding during the inspection.

Oil buildups in a sump located at the #21 Fuel Oil Storage Tank and in the Diesel Generator Rooms were reported by the resident inspectors to the Plant Superintendent. Timely corrective action was taken and a commitment was made to keep these areas clean.

Four fires occurred during the evaluation period: fire in chemically soaked cleaning rags inside Containment during an outage, fire in the Outage Planning Room, and two fires in a temporary structure erected inside the Auxiliary Building. Only the fires in the temporary building originated from a common cause (both were initiated by sparks from a spent fuel rack cutup operation) and perhaps could have been avoided through better planning. It should be noted, however, that a significant amount of pre-planning was done by the licensee for this cutup operation including addition of a special sprinkler system. In all cases, response was rapid and effective.

There has been a great improvement in the documentation of fire brigade training, instructions and drills. The licensee's records and information as to fire brigade status is current, readily available and easily interpreted.

As a indication of management's commitment to fire protection, the fire protection staff has been increased from three to six people. These individuals have been assigned to round the clock operating shifts, and perform the duties of Fire Brigade leaders. The Senior Control Room Operator, who formerly fulfilled the duties of Fire Brigade leader, now acts as a technical advisor to the brigade. At least four members of the fire protection staff are also members of local volunteer fire departments. Currently, two of these individuals serve as Fire Chief and Deputy Fire Chief for the Solomons Island Fire Department.

One violation was identified in this area: failure to test a ventilation filter following a fire.

Fire Protection and Housekeeping programs at Calvert Cliffs are effective and are aggressively pursued by the licensce.

Conclusion

Category 1

Board Recommendations

Reduce Regional inspection pending Appendix R team inspection outcome.

6. Emergency Preparedness (14%)

Three region based inspections were conducted. The resident inspectors monitored the area throughout the period.

During the periods January 31 - February 1, 1983, and February 7 - 10, 1983, a followup inspection was performed of the open items from the Emergency Preparedness Implementation Appraisal (EPIA). It was determined that 23 of the 28 Appendix A items and 42 of the 44 Appendix B items were completed. It was also determined that there were no deficiencies in regard to the Prompt Public Notification System.

During the period July 23-29, 1983, a followup inspection was performed of the EPIA open items. It was determined that all Appendix A and Appendix B items had been completed.

One full scale emergency exercise, with NRC Region I participation, was evaluated. One medical drill was evaluated. Three emergency plan drills were observed by the resident inspectors.

Several times during the evaluation period, the licensee implemented portions of the Emergency Plan (Fires and Radiological Events). The plan and its required actions were adequate for coping with the events. Licensee response, in general, was acceptable.

The NRC expressed a concern that the Emergency Plan was somewhat difficult to use (personnel sometimes became confused when trying to chain through event procedures). The NRC urged that the licensee seek ways to simplify the plan. The licensee had internally reached the same conclusion and later issued a major change to improve the plan.

During the period a general weakness in the Emergency Plan regarding inadequate procedural guidance for spills of radioactive liquid was identified and corrected.

There were no violations or reportable events during the assessment period which related to the licensee's state of emergency preparedness. The licensee has been responsive to NRC initiatives and the findings indicate an acceptable level of performance in emergency preparedness.

Conclusion

Category 2

Board Recommendations

None.

7. Security and Safeguards (9%)

During the assessment period, there were two routine physical protection inspections and one NRC Safeguards management meeting held onsite. Routine resident inspections continued throughout the assessment period.

During the first half of the assessment period, there were four Severity Level IV violations identified. These violations were minor in nature and did not represent any potential programmatic problems. A followup physical protection inspection was conducted prior to the licensee's response to the four violations. Corrective actions had been taken on the previous violations and no new violations were identified.

Interviews and observations throughout the assessment period indicated a management commitment to provide and maintain an effective security organization capable of implementing the security program. Both the plant and corporate security management staff appeared well qualified. The individuals responsible for three programmatic areas (access control and background screening, security support services, and security training) were upgraded to supervisors during the assessment period, demonstrating licensee management's attention to and support of the security program. This change will allow more effective oversight of the security program.

In addition, steps were taken to completely revise the Physical Security Plan format to ensure more effective utilization of the plan. Also, the licensee conducted a joint test of the Security Contingency Plan with local, state , and federal law enforcement authorities to familiarize plant security personnel with their roles and responsibilities.

Security program audits were completed and timely. Management responded to audit findings with satisfactory corrective action. NRC inspections revealed that records management is very effective and records were readily accessible to inspectors. Excellent cooperation and frankness was exercised by all staff supervisors during interviews and in aiding in the resolution of inspection-related questions.

Four Security Event Reports prepared pursuant to the requirements of 10 CFR 73.71 were submitted. Each event concerned hoax bomb threats. It appeared that compensatory security measures for security-related incidents were timely and adequate.

Licensee and contract security personnel appeared to peform their duties and responsibilities in an excellent manner. The Security Training Organization is well staffed and efficiently implemented.

Conclusion

Category 1

Board Recommendations

Assign low priority to specialist support and reduce inspection coverage.

8. <u>Refueling (6%)</u>

One major refueling/modification outage was conducted at Unit 2 (October 1982-January 1983) and preparations were made for a Fall 1983 Unit 1 refueling outage. The December, 1982 SALP Report concluded that refueling was a Category 1 functional area.

Three inspections were conducted by region-based inspectors and the resident inspectors reviewed refueling activities throughout the period. There were several unscheduled outages at both units for equipment repairs.

Refueling or refueling related activities observed by resident and regional inspectors included Auxiliary Feedwater System modifications and testing, installation of new Containment electrical penetrations, fuel loading, integrated and local leak rate testing, personnel door lock modifications, Spent Fuel Rack disassembly and replacement, new fuel receipt, startup and startup testing, outage coordination, and employee training. Additionally, the inspectors attended outage status meetings, made general tours of the plant including Containment, and reviewed the general condition of safety-related equipment, component tagging, radiological controls, and system lineups.

During this period, outage planning, scheduling, and conduct was well controlled under a formal plant procedure and was effective. The licensee supplements a core planning staff with a matrix organization consisting of supervisory personnel, work leaders, and engineers from all plant groups. This organization formulates an outage work list six - nine months in advance of the outage. Near the outage, the work list is converted into a project plan and schedule which then receive corporate level management approval. During an outage, one planning meeting and two status meetings are held daily. Following outage completion, post outage reviews are held to critique activities and improve the overall process. The effectiveness of the licensee's outage control process is demonstrated by the high cumulative availability factors achieved by both units (79.2% for Unit 1 and 83% for Unit 2).

During the last SALP reporting period, 10CFR50.59 evaluations for Facility Change Requests (FCR's) were discussed under a separate section entitled "The Change Control Process" and found to be inadequate in that they were too often simple statements of conclusion without a stated supporting basis. A general improvement has been noted by the resident inspector in the quality of evaluations reviewed. No discrepancies were noted in the evaluations reviewed by a regional inspector in an examination of design changes and modifications.

One inspection reviewed the areas of document control and design changes and modifications. In the area of document control one Level IV violation and six unresolved items were identified. Since each department controls its own documents, the deficiencies noted apply to the licensee in general and not to the QA Department.

The licensee has had a previous enforcement history in the area of document control and for this reason it had established a document control task force. However, the results of this task force have not been implemented in a timely manner and will be issued eight months later than expected. The deficiencies noted during inspection indicate a lack of initiative in recognizing document control problems, for example, a failure to recognize that the use of aperture card printouts was bypassing the drawing control system.

Although the licensee has taken strides in improving document control, findings identified by the NRC and licensee (QA Audit 31-82) indicate a great deal of corrective actions still need to be performed. The above identified numerous errors in administering the document control system. Additionally, NRC inspection identified the following deficiencies:

1. The use of uncontrolled aperture card printouts and hard copy drawings to perform work on safety related equipment;

2. The failure to follow document distribution lists established in procedures;

3. The failure to establish a procedure to ensure drawings are updated following modifications; and

4. The failure to establish controls which would facilitate drawing and procedure distribution.

Although not a violation or deficiency and not identified in an inspection report, the licensee allows each section to make its own procedure distribution. This appears to increase the chances for document control errors.

Additionally, in the area of design changes and modifications two unresolved items were identified. One unresolved item noted that drawings which had been updated as a result of plant modifications were not being properly distributed onsite. This problem was related to document control problems already discussed above. The second unresolved item identified that there was a significant backlog of "after-the-fact" review of safety evaluations that needed to be performed by the Offsite Safety Review Committee. The licensee had already recognized the problem and was taking corrective actions.

Other than the descrepancies delineated in the preceding paragraph, management control, resolution of safety issues, staffing and training of personnel as applicable to the area of design change and modification control was acceptable.

During the reporting period iodine levels in the RCS have increased, probably due to a small number of leaking fuel pins.

Two violations were identified: placing of Unit 2 in Mode 6 without audible indication of Source Range Neutron Flux and deficiencies in document control.

Overall, refueling and outage activities have been effectively and efficiently accomplished by the licensee.

Conclusion

Category 2

Board Recommendations

NRC Region I should perform followup inspection to confirm licensee corrective actions to deficiencies noted in the document control area.

Due to the indication of possible fuel leakage, the licensee should consider "sipping" fuel during the next Unit 2 refueling outage and replace leaking fuel pins.

9. Licensing Activities

The overall evaluation of "Licensing Activities" for BG&E was based upon the following activities:

-- Operator Candidate Licensing Examinations

-- Inservice Inspection

-- Unit 2, Cycle 5 Reload

-- Technical Specification change regarding pressurizer level

-- Review of FATES-3 methodology

-- Review of exemptions to Appendix R to 10CFR Part 50

-- Control of heavy loads over critical areas

-- Review of the Hermite/MacBeth methodology

-- Technical Specification changes regarding Containment tendons

-- Resolution of concerns associated with IE Bulletin 80-04

-- General licensing activities.

In the previous SALP review of BG&E, an uncertainty regarding the assignment of leadership for resolution of licensing issues was noted. This problem appears to have resulted from an evolution in the assignment of plant/home-office responsibilities. This problem seems to have been largely eliminated during the SALP reporting period. The licensee maintains a clear policy for lead responsibility for Technical Specification changes, TMI action items, fire protection, and other areas.

During the SALP reporting period, it appears that BG&E's management provided insufficient control of plant changes that require prior changes to the Technical Specifications. In two cases, removal of snubber 1-60-7 and modification to valves (1)2-SV-6529, the changes were made to the plant prior to the submittal of the application for licensing amendment contrary to the intent of 10CFR Part 50, Section 50.59. In a third case, a non-safety grade control room air conditioner was installed which had an important impact on the TS. Since normal operation of the safety grade air conditioner was recognized as appropriate surveillance in the TS and since the non-safety grade system replaced the safety grade system for normal operation, the TS became ineffective with regard to the safety grade system. Finally, in the case of changes to the remote shutdown and post-accident monitoring instrumentation, the application for licensing amendment was submitted almost concurrently with the performance of the modifications.

The licensee has shown considerable improvement in the technical quality of the submittals to the NRC, especially in the area of application for license amendments (Technical Specification changes). This situation is attributable to the considerable technical skill and depth of the BG&E staff. The licensee continues to effectively utilize consultants, especially Combustion Engineering and Bechtel, for areas where BG&E lacks particular capabilities.

In one area, during the SALP review period, the licensee failed, initially, to appreciate the significance of the safety issues associated with IE Bulletin 80-04 (IEB 80-04) and resisted NRC staff requests for full analysis of the IEB 80-04 scenario.

The scenario addressed in IEB 80-04 involves a main steam line break with continued feedwater addition due to a failed feedwater regulating valve. BG&E eventually recognized that the IEB 80-04 scenario was applicable to Calvert Cliffs and thereafter provided all information requested by the NRC.

The licensee continues to meet frequently with the ORPM, to discuss scheduling of BG&E submittals. Except with regard to IEB 80-04, the licensees' submittals are made in a timely manner and are of sufficient quality to allow timely resolution of most issues.

The licensee continues to have a policy for timely and forthright reporting of operational events of importance. In at least two cases, the analysis of operational events resulted in remedial action which was insufficient:

-- Calvert Cliffs had experienced numerous violations of the Technical Specification (TS) limits on pressurizer level. The licensee was encouraged to request a TS change to establish more realistic pressurizer level limits. On January 25, 1983 TS were issued to revise the pressurizer level limits in accordance with BG&E's request. The corrective action, revised pressurizer level limits, did not prove to be wholly effective in resolving problems associated with pressurizer level deviations associated with startup transients.

-- The licensee has experienced a number of reportable events associated with failure of the CEA reed switch stack position indication system. The licensee had requested consideration in the TS for operability of the reed switches associated with the upper and lower electrical limits for the CEAs in order to allow continued reactor operation in the event that additional read switch stacks became inoperable. This TS change was issued on February 8, 1982. This remedial action did not prove to be wholly successful in that BG&E requested a second TS change on this subject (issued May 5, 1983) and presently has a third request pending (application dated September 20, 1983).

Operator licensing examinations were administered to Baltimore candidates in October 1982 and May, 1983. The complete examinations included written and in-plant portions. The first group consisted of eight Reactor Operator and four Senior Reactor Operator candidates. The latter group consisted of 13 Reactor Operator and four Senior Reactor Operator candidates. All candidates (21 Reactor Operators, eight Senior Reactor Operators) successfully passed the examinations and received licenses.

During the SALP reporting period, BG&E has made considerable progress in improving the quality of licensing submittals. In addition, the overall management of licensing activities appears to be better organized with regard to assignment of issues between the plant site and the corporate office. Training for licensed operators appears appropriately defined and implemented.

During this same period, BG&E has had some difficulty in interpreting the requirements of 10 CFR Part 50, Section 50.59 in that several plant modifications have occurred, prior to NRC approval, which affect the Technical Specifications. In addition some requests for TS changes, needed to alleviate operational problems, have not been entirely successful in this regard. The result has been that additional review by the NRC staff has been required.

Conclusion

Category 2

Board Recommendations

Additional management overview is merited to assure that proposed TS changes: (1) are submitted to the NRC in a timely manner to allow for review where equipment modifications are involved, and (2) are reviewed to assure that, where operational relief is sought, the TS change will achieve the desired result. Specifically, pressurizer level violations should be eliminated.

V. SUPPORTING DATA AND SUMMARIES

1. Licensee Event Report (LERs)

Tabular Listing

Type of Events:

A. Personnel Error. 14

B. Design/Man.Constr./Install 10

C. External Cause 1

D. Defective Procedure 13

E. Component Failure 57

X. Other 46

Total 141

Licensee Event Reports Reviewed:

Report Nos. 317/82-58 through 83-54; and 318/82-45 through 83-53.

a. Causal Analysis (Review period October 1, 1982-September 30, 1983)

Twelve chains were identified:

(1) LER's 318/82-55 and 318/83-01 concern loses of vital instrument buses similar failures due to malfunctions of inverter (#21 and #22) current limiting devices and improper fusing of vital bus loads. The licensee removed the current limiting features of the inverters which supply power to ESFAS actuation cabinets on both units and installed proper fuses on the vital instrument A.C. buses.

(2) LER's 318/83-55, 318/83-39, and 318/83-50 report failures of air actuator diaphragms for the two new (installed during October 1982-January 1983 outage) Unit 2 Auxiliary Feedwater Pump steam supply valves. Each diaphragm failure has been attributed to a different cause (which have been corrected) and, therefore, this chain may not necessarily be indicative of future component reliability problems.

(3) LER's 317/82-74, 318/83-24, and 318/83-49 concern vibration induced cracks in welds of the charging portion of the Chemical and Volume Control System.

(4) LER's 317/82-72, 317/82-86, 317/83-22, 317/83-27, 317/83-48, 317/83-52 concern higher than normal radioactive (Ag 110m) material concentrations in oyster samples near the plant. The higher activity levels were attributed by the licensee to the natural tendency of oysters to bioconcentrate silver.

(5) LER's 317/83-41, 318/83-37, 318/83-45, and 317/82-70 describe apparent early design and/or construction deficiencies associated with the ECCS pump room exhaust system filter dampers and fan discharge dampers (filter dampers incorrectly installed and no air accumulators installed for discharge dampers), penetration room fan discharge dampers (only one air accumulator installed), and CVCS isolation system sensors (sensors located in physically separate rooms such that the actuation logic [two of four] would only have been satisfied if both sensors in a particular room functioned). See Plant Operators Analysis Section for further detail.

(6) LER's 317/83-40 and 317/83-39 concern similar problems with Control Room air conditioning units #11 and #12 condenser fan drive shaft set screws vibrating loose causing belt and fan support structural damage. In both cases a "Loctite" compound was applied to the set screws to prevent recurrenc

(7) LER's 317/83-17 and 317/83-35 describe failures of ESFAS system isolators manufactured by Vitro. The licensee has been experiencing a relatively high failure rate of the Vitro isolators and has, with vendor assistance, determined a common cause problem to be a component called an "opto isolator". Improved opto isolators are now available, and the licensee plans to replace this component in all ESFAS isolators (20 per unit) during each unit's next refueling outage.

(8) LER's 317/82-61, 317/82-73, 317/82-79, 317/83-05, 318/83-09, and 318/83-30 describe pressurizer level deviation outside the operating band required by technical Specifications (TS). A TS was requested and issued (January 25, 1983) to expand the allowed TS band. Between January 25 and the end of the reporting period two additional level deviations were reported on Unit 2. Shortly after the evaluation period (October 19, 1983) a third Unit 2 level deviation was reported. See Licensing Analysis Section for further discussion.

(9) LER's 317/83-08, 317/83-26, 317/83-36, and 317/83-43 concern similar CEA reed switch position indication failures due to shorts in reed switch position transmitters. The licensee believes there is a common cause manufacturing defect in

these components (which were recently installed on both units). The licensee plans to replace all these devices during the current (Fall 1983) Unit refueling outage and the next Unit 2 refueling outage.

(10) LER's 318/83-12, 318/83-29, 318/83-37, and 318/83-51 report iodine spikes in RCS activity due to a small number of leaking fuel pins (in conjunction with power level changes).

(11) LER's 318/83-40 and 318/83-41 report four occurrences of cold leg RCS temperatures exceeding their TS limit due to a common malfunction(s) in the main turbine control system.

(12) LER's 318/82-53, 318/83-17, 318/83-02, 318/83-40, 318/83-05, and 318/83-07 concern technician/operator error events. See Maintenance Analysis Section for further discussion of personnel error events.

b. Office of Analysis and Evaluation of Operational Data (AEOD) Review

AEOD review of Licensee Event Reports submitted during the evaluation period examine the following items:

1. Review of LERs for Completeness

(a) Sufficient Information

The information in the free-form narrative sections of the LER Form was consistently brief. There were no instances of overruning narratives, a recurring problem with some licensees. Despite the conciseness of the licensee response in the two free-form sections of the LER Form, the information was exceptionally informative, complete and meaningful. The licensee was found to have properly interpreted and complied with the intent of the procedures of NUREG-0161.

(b) Review of Coded Information

AEOD disagreed with the licensee selection of component code. The root cause of this disagreement was perceived to be the licensee's use of the not applicable code for events where a failed component was not directly involved. In this case, according to NUREG-0161 a related component, or the first component to malfunction should have been listed. In addition, some environmental reports and updated reports were not properly designated as such in their respective code fields. Except in a few other infrequent cases, AEOD agreed with the licensee's selection of coded information in the other fields. In view of the quantity of coded information available in this review (approximately 120 x 40) and the subjectiveness of some code decisions, the digital information was more than satisfactory.

(c) Supplemental Information

All of the reports that were required to be reported immediately contained the mandatory supplemental information. In addition, a significant number of reports contained voluntary additional supplementary information. The attachments that were provided typically included specific information useful in assessing the full impact of the event. The licensee's safety assessment of the event was meaningful and its potential consequences could be determined by someone reasonably familiar with the plant. AEOD was particularly impressed with the completeness of the attachments for LERs 317/83-21 and 318/83-03. Reports without attachments did not need additional explanation. AEOD concluded that the licensee responded with additional information readily and the additional information was pertinent and useful.

(d) Follow-up Reports

The licensee promised to update 14 reports for the two units in this assessment period; five of these reports have been received. During the review, it was noted that many reports that were not originally committed to be updated were revised and updated by the licensee. A check of the data base found that many older reports from previous assessment period were also updated. The updated reports included new information and were updated correctly in accordance with the guidelines of NUREG-0161. AEOD concluded that the licensee was very responsive in providing updated reports.

(e) Similar Occurrences

Previous LER numbers of events of a similar nature were referenced correctly. In addition, the licensee positively stated when there have been no similar previous reports.

2. Component Failure Reporting

The licensee indicated that they have been reporting to NPRDS throughout the assessment period for both units.

3. Multiple Event Reporting in a Single LER

The licensee combined multiple events correctly into a single LER in accordance with the guidance offered in NUREG-0161.

2. Investigation Activities

No investigations were conducted during the evaluation period.

3. Escalated Enforcement Actions

a. Civil Penalties

Two civil penalty actions were initiated during this period: inoperability of both Unit 1 ECCS pump room air coolers and inoperability of #12 diesel generator due to valving error. The "Notice of Violations and Proposed Imposition of Civil Penalties" was issued on November 4. 1983.

b. Orders

On March 16, 1983, the Commission issued an Order confirming Baltimore Gas and Electric's commitments on Post-TMI Related Issues.

c. Confirmatory Action Letters

No Confirmatory Action Letters were issued during this period.

4. Management Conferences

November 29, 1982 Management Meeting held in the NRC Region I Office for the Systematic Assessment of Licensee Performance.

February 24, 1983 Management Meeting held in the NRC Headquarters Office to address ESFAS actuations at Calvert Cliffs and specifically: (1) equipment modifications to reduce challenges to the ESFAS, (2) behavior of the ESFAS under electrical transient conditions, and (3) the role of personnel error in plant occurrences.

July 1, 1983 Enforcement Conference held in the NRC Region I Office to discuss the violation associated with the alignment of the Salt Water System for maintenance/drainage which resulted in the simultaneous isolation of both ECCS Pump Room air coolers on Unit 1.

September 2, 1983 Enforcement Conference held in the NRC Region I Office to discuss the inoperability of shared Diesel Generator No. 12.

TABLE 1

TABULAR LISTING OF LERS BY FUNCTIONAL AREA

CALVERT CLIFFS NUCLEAR POWER PLANT

AREA	TOTAL-NUMBER/CAUSE CODES
1. Plant Operations	2/A 7/B 1/C 8/D 43/E 23/X
2. Radiological Controls	0/A 0/B 0/C 1/D 0/E 0/X
3. Maintenance	7/A 1/B 0/C 2/D 3/E 4/X
4. Surveillance	4/A 2/B 0/C 3/D 10/E 18/X
5. Fire Protection	0/A 0/B 0/C 0/D 0/E 1/X
6. Emergency Preparedness	None
7. Security & Safeguards	1/A 0/B 0/C 0/D 0/E 0/X
8. Refueling	None
9. Licensing Activities	None

			U1	U2	Combined
Cause Codes:	A.	Personnel Error	7	7	14
	B.	Design/Man.Const./Install	6	4	10
	C.	External Cause	1	0	1
	D.	Defective Procedure	7	6	13
	E.	Component Failure	32	25	57
	X.	Other	25	21	46
		Totals	78	63	141

TABLE 2

INSPECTION SUMMARY HOURS (10/1/82-9/30/83)

CALVERT CLIFFS NUCLEAR POWER PLANT

		HOURS	% OF TIME
1.	Plant Operations.	1051	37
2.	Radiological Controls	268	10
3.	Maintenance	241	9
4.	Surveillance	312	11
5.	Fire Protection/Housekeeping.	106	4
6.	Emergency Preparedness	396	14
7.	Security and Safeguards	246	9
8.	Refueling	165	6
9.	Licensing Activities	N/A	N/A
	Totals	2785	100

TABLE 3

VIOLATIONS (10/1/82-9/30/83)

CALVERT CLIFFS NUCLEAR POWER PLANT

A. Number and Severity Level of Violations

Severity Level I	0
Severity Level II	0
Severity Level III	2
Severity Level IV	13
Severity Level V	6
Total Violations	21

B. Violations Vs. Functional Area

Functional Areas	Severity Levels I	II	III	IV	V
1. Plant Operations				2	1
2. Radiological Controls				3	4
3. Maintenance			2		
4. Surveillance				1	1
5. Fire Protection/Housekeeping				1	
6. Emergency Preparedness					
7. Security and Safeguards				4	
8. Refueling				2	
9. Licensing Activities					
Totals			2	13	6

Total Violations = 21

SUMMARY

Inspection Number	Inspection Date	Require-ments	Severity	Area	Subject
318/82-23	10/12-11/9	TS	IV	8	U2 was placed in Mode 6 operation without an operable audible indication of source range neutron flux in the Control Room.
317/82-28 318/82-24	11/1-11/5	Security Plan	IV	7	Failure to take specific compensatory measures.
"	"	"	IV	7	Protected area entry.
"	"	"	IV	7	Failure to control packages.
"	"	"	IV	7	Failure to have all alarms annunciate.
317/83-01 318/83-01	1/17-1/21	10CFR20	V	2	Failure to prepare and follow personnel radiation exposure procedures.
317/83-03 318/83-03	1/17-1/21	10CFR50	IV	8	Distribution of drawings and procedures were not properly controlled and activities affecting quality were not prescribed by or accomplished in accordance with appropriate up-to-date drawings or procedures.
318/83-08	4/4-4/8	TS	IV	2	All effluent strontium analysis for third quarter of 1982 had chemical yields less than 50% but the Chemical Supervisor was not contacted for guidance as required.

Inspection Number	Inspection Date	Requirements	Severity	Area	Subject
318/83-08	4/4-4/8	TS	V	2	For the period 1/83 through 3/83, all waste gas decay tank releases were sampled and analyzed in a 25 ml gas Marinelli beaker instead of the gas vial.
317/83-11 318/83-11	4/12-5/10	TS	IV	5	Fire in a ventilation zone communicating with the SFP Ventilation System, the licensee did not have a procedure or other controls established requiring performance of specified test.
317/83-11	4/12-5/10	ETS	IV	2	Required grab sampling was not initiated when the Main Vent Particulate Monitor became inoperable sometime between 4/13-4/24 until 4/26/83.
317/83-13 318/83-13	5/10-6/14	10CFR50	IV	1	Facility change was made without prior NRC review and approval when Reactor Coolant Drain Tank Oxygen Sample Containment Isolation Valve was changed to a Post Accident Sampling System return valve.
"	"	TS	IV	1	Procedures for startup and operation of Component Cooling Water System not properly established and implemented.
"	"	TS	V	4	STP M-76-0 was not adequately implemented in that the procedure directed the operation of the pump at shutoff head without recirculation flow and did not require verification of circula-

Inspection Number	Inspection Date	Requirements	Severity	Area	Subject
					tion flow through the pump discharge relief valve when operated without a flow discharge path.
317/83-15 318/83-15	5/25-6/1	TS	III	3	During Unit 1 full power operation, both ECCS and CSS systems were inoperable in that required auxiliary equipment-both ECCS air room coolers were inoperable.
317/83-17 318/83-17	6/27-7/1	TS	V	2	Licensee did not comply with procedures in that three separate containers of liquids were found to be in a package of radioactively contaminated material prepared for shipment.
"	"	TS	V	2	Licensee did not perform leakage and/or contamination test at least every six months on two 1 curie sources installed in the boronometers.
317/83-21 318/83-21	8/9-10/13	TS	V	1	High Boric Acid Concentrations in RWT not reported to Shift Supervisor.
317/83-22 318/83-22	8/17-8/22	TS	III	3	Spare Diesel Generator inoperable for greater than the time period allowed by TS (degraded mode) due to isolated Day Tank level switches.
317/83-23 318/83-23	8/2-9/2	TS	IV	2	Failure to establish procedures to collect and maintain liquid rad-waste

Inspection Number	Inspection Date	Requirements	Severity	Area	Subject
					from temporary decon facility into liquid rad-waste system.
317/83-26 318/83-26	9/19-9/23	TS	IV	4	Surveillance procedure not properly established and implemented.

TABLE 4

INSPECTION REPORT ACTIVITIES

Unit1/Unit2 REPORT NOS.	INSPECTOR	HOURS	AREAS INSPECTED
82-27/82-23	Resident	80	Routine inspection.
82-28/82-24	Specialist	76	Site Orientation; Security Plan and Implementing Procedures; Security Organization; Security Program Audit; Records and Reports; Testing and Maintenance; Locks, Keys and Combinations; Physical Barriers; Access Controls; and Alarm Stations.
82-29/82-25	Resident	123	Routine inspection.
82-26	Specialist	41	Procedure Review, witnessing and results Evaluation of Local Leak Rate Test and Integrated Leak Rate Test.
82-30/82-27	Resident	123	Routine inspection.
83-01/83-01	Specialist	44	Radiation Protection Program.
83-02/83-02	Resident	247	Routine inspection.
83-03/83-03	Specialist	68	Quality Assurance Program Implementation.
83-04/83-04	Specialist	48	Follow-up inspection of Emergency Preparedness items from appraisal of October 5-16, 1981.
83-05/83-05	Resident	140	Routine inspection.
83-06/83-06	Specialist	72	Physical Barriers; Security System Power Supply; Lighting; Assessment Aids, Access Controls; Alarm Stations; Communications; Safeguards Contingency and Guard Training and Qualification Plans.
83-07/83-07	Resident	153	Routine inspection.
83-08/83-08	Specialist	43	Chemical and Radiochemical Measurements Program using NRC:I Mobile Radiological Measurements Laboratory.
83-09/83-09	Specialist	16	Environmental Monitoring Program for Operations.

Unit1/Unit2 REPORT NOS.	INSPECTOR	HOURS	AREAS INSPECTED
83-10/83-10	Specialist	71	Licensee Actions on Previous Inspection Findings; Audit Program; Organization; and Quality Control and Surveillance Program.
83-11/83-11	Resident	160	Routine inspection.
83-12/83-12	Specialist	42	Radiation Protection Program.
83-13/83-13	Resident	124	Routine inspection.
83-14/83-14	NA		Report number cancelled.
83-15/83-15	Resident/ RI Management	51	Special inspection to review isolation of Saltwater to Emergency Core Cooling System Pump Room Air Coolers. Enforcement Conference held.
83-16/83-16	Resident	93	Routine inspection.
83-17/83-17	Specialist	41	Radiation Protection Program.
83-18/83-18	Resident	104	Routine inspection.
83-19/83-19	Specialist	34	Fire Protection/Prevention Program.
83-20/83-20	Specialist	30	Follow-up inspection of Emergency Preparedness items from appraisal of October 5-16, 1981, follow-up inspection of January 31-February 1, 1983, and February 7-10, 1983.
83-21/83-21	Resident	128	Routine inspection.
83-22/83-22	Resident	17	Special inspection to review the inoperability of Diesel Generator #12 during period of August 10-16, 1983.
83-23/83-23	Specialist	40	Radiation Protection Advance Planning, Rad-Safety Staffing for Outage, Rad-Worker Training, Rad-Protection Personnel Qualification and Training, Steam Generator Dosimetry Placement, Status of 10CFR61 Preparation.
83-24/83-24	Specialist	16	Review of Administrative and Procedural Controls governing 50.59 reviews specifically in the area of maintenance activities and procedure changes.

Unit1/Unit2 REPORT NOS.	INSPECTOR	HOURS	AREAS INSPECTED
83-25/83-25	Specialist	280	Emergency Preparedness Inspection; Observation of licensee's emergency exercise on September 14, 1983.
83-26/83-26	Specialist	76	Surveillance, Calibration and QA Program Description Review.
83-27/83-27	Resident	171	Routine inspection.

Table 5

CALVERT CLIFFS NUCLEAR POWER PLANT

LER SYNOPSIS

October 1, 1982 - September 30, 1983

LER Number	Type	Summary Description
Unit 1		
82-58	30 day	ESFAS Sensor Channel ZE Inoperable
82-59	30 day	RPS Channel D Trip Units for High Power Thermal Margin/Low Pressure & Axial Shape Index Bypassed
82-63	30 day	Spent Fuel Pool Ventilation System Inoperable
82-64	30 day	RWT Inadvertently Drained to Spent Fuel Pool to Level of 455"
82-65	30 day	Containment Atmosphere Particulate & Gaseous Radioactivity System Inoperable
82-66	30 day	RPS Ch 3 Trip Units Bypassed
82-67	30 day	Safety Injection Tank Level Transmitter Inoperable
82-68	30 day	DC Feeder Breaker to 120 V AC Vital Bus #11 Inverter Tripped Open Causing Reactor Trip
82-69	30 day	AFW Pump Inoperable
82-70	24 hour	Location of Pressure Transmitters Supplying Inputs to Generate CVCIS Located Such That Single Failure of Sensor Channel May Prohibit CVCIS Initiation in Event of Letdown Line Break
82-71	30 day	#12 Charging Pump Inoperable
82-72	ETS	Oyster Samples Collected per ETS Showed AG-110m to be 363±.8pci/kg

LER Number	Type	Summary Description
82-73	30 day	Pressurizer Level Deviated Slightly from Program Level by more than 5%
82-74	30 day	Water Leak from Cracked Weld on #11 Charging Pump Discharge Drain Line
82-75	30 day	#11 CCU Tripped;#12 DG Emergency Power Source for #14 4kv Bus & #13 & #14 CCU's Inoperable
82-76	30 day	#12 Containment Air Cooler Fan Inoperable
82-77	30 day	Incore Detector Monitoring System Inoperable
82-78	30 day	Containment Particulate Radiation Monitor Inoperable
82-79	30 day	Pressurizer Level Deviated from Program Level by more than 5%
82-80		Cancelled-non-reportable
82-81	30 day	Snubber 1-83-53 Inoperable
82-82	30 day	Continuous CEA Motion Inhibit Signal in effect Causing CMI Inoperability
82-83	30 day	RPS Channel A Trip Units for Low SG Level, Low SG Pressure & Thermal Margin/Low Pressure Bypassed for Maintenance
82-84	30 day	Sequencer Initiated Alarm Inoperable
82-85	30 day	ESFAS AL Sequencer Inoperable
82-86	ETS	Oyster Samples Show ag-110m to be 532±12 and 458±12 pci/kg
83-01	30 day	AFW Flow Indication Inoperable
83-02	30 day	Containment Sump Pump Inoperable
83-03	30 day	One cell of #22 125 V battery had a low individual cell voltage

LER Number	Type	Summary Description
83-04	30 day	Containment Sump Level Alarm Inoperable
83-05	30 day	Pressurizer Level deviated from program level by more than ±5%
83-06	30 day	Intake Structure Door IS-1 found Open
83-07	30 day	#11 ECCS Pump Room Fan Discharge Damper Inoperable
83-08	24 hour	CEA 26 RSPI Inoperable
83-09	30 day	Snubber 2-15-10 not included in U2 T.S. and STPs.
83-10	30 day	#11 Boric Acid Storage Tank Inoperable
83-11	30 day	RWT level decreased below the limit of T.S. 3.5.4.a
83-12		Cancelled
83-13	30 day	Hydrogen Analyzer 0-AE-6519 Inoperable
83-14	30 day	Nos. 12 and 13 Charging Pumps Inoperable
83-15	30 day	Incore Detector Monitoring System Inoperable
83-16	30 day	Low Level Radioactive Water and and Resin spill in Spent Resin Metering Tank Room
83-17	30 day	ESFAS cabinet ZD deenergized for corrective maintenance
83-18	30 day	#12 Emergency Diesel Generator Inoperable
83-19	24 hour	Power Operated Relief Valve ERV-404 opened; ERV-202 short circuited rendering it Inoperable
83-20	30 day	Weld leak in Sealing System for No. 11A RCP.

LER Number	Type	Summary Description
83-21	24 hour	Main Steam Line Break Event Analysis
83-22	EST	Oyster samples collected showed Ag-110m to be 464±41pCi/kg (wet)
83-23	30 day	Containment Pump Alarm Inoperable
83-24	30 day	Snubber 1-64-1 Inoperable
83-25	30 day	T Hot to Channel A RPS failed rendering High Power, Thermal Margin/Low Pressure and Axial Power Distribution Inoperable
83-26	30 day	CEA 18's Reed Switch Position Transmitter Inoperable
83-27	ETS	Oyster samples collected showed Ag-110 to be an average 416±24 pCi/kg (wet)
83-28	24 hour	No. 11 and No. 12 ECCS Pump Room Air Coolers Inoperable
83-29	30 day	No. 11 and No. 12 Spent Fuel Pool Exhaust Fans Inoperable
83-30	30 day	Incore Monitoring System Inoperable
83-31	30 day	T Hot to Channel A RPS failed rendering High Power, Thermal Margin Low Pressure and Axial Power Distribution Inoperable
83-32	30 day	CIS "B" Logic Module Inoperable
83-33	30 day	Boric Acid Concentration in #11 and #12 BAST exceeded limits of TS
83-34	30 day	No. 12 ECCS Pump Room Cooler Inoperable
83-35	30 day	ESFAS Channel ZG SG Level Tripped
83-36	24 hour	CEA Reed Switch Position Indicator Channels Inoperable

LER Number	Type	Summary Description
83-37	30 day	Reactor Trip Circuit Breakers and Undervoltage Device Response Time Slower than Allowed by TS
83-38	30 day	#12 Auxiliary Feedwater Pump Inoperable
83-39	30 day	#12 Control Room Air Conditioner Inoperable
83-40	30 day	#11 Control Room Air Conditioner Inoperable
83-41	24 hour	ECCS Pump Room Exhaust Ventilation System Inoperable
83-42	30 day	Auxiliary Feedwater Flow Indicator to #11 SG Inoperable
83-43	24 hour	Loss of CEA Reed Switch Position Indication Channels
83-44	30 day	#12 Diesel Generator Tripped on Low Jacket Cooling Water Pressure
83-45	30 day	CNMT Atmospheric Gaseous and Particulate Radiation Monitors Discharge Solenoid Valve Inoperable
83-46	24 hour	#12 Swing Diesel Generator Inoperable
83-47	30 day	#12 Control Room Air Conditioner Compressor Inoperable
83-48	ETS	Oyster Samples Collected During 2nd Quarter '83 showed AG-110m to be 214±10 pCi/kg (wet)
83-49	30 day	Auxilliary Feedwater Pump Inoperable
83-50	30 day	#12 Hydrogen Analyzer Inoperable
83-51	30 day	#12 Diesel Generator Inoperable
83-52	ETS	Oyster Samples Collected during August, 1983 showed Ag-110m to be 118±8 pCi/kg (wet)

LER Number	Type	Summary Description
83-53	30 day	Charcoal Filter Bypass Damper for Spent Fuel Pool Ventilation System Inoperable
83-54	30 day	T Input to Channel "C" Reactor Protective System Trip Units to Power Level, Axial Flux Offset and Thermal Margin/ Low Pressure Failed
Unit 2		
82-45	30 day	RPS Low Flow Trip Unit Ch A Failed
82-46	30 day	RPS Ch C Trip Unit for High Pressurizer Pressure Tripped
82-47	30 day	#23 HPSI Pump Breaker Inoperable
82-48	30 day	#21 SF Safety Valve Set to Lift at 929 psig vs 1035 psig ±1%
82-49	24 hour	Unplanned Reactivity Insertion of More than 5% K/K
82-50	30 day	MSIV Strocked Shut in 12.72 sec.
82-51	30 day	Turbine Bldg. Service Water Isolation Valve Inoperable
82-52	30 day	Audible Source Range Indication Inoperable
82-53	30 day	Shutdown Cooling Flow Lost
82-54	30 day	Power Lost to 24 4kv Bus with Loss of #25 Saltwater Pump & #22 LPSI Pump Disabling Shutdown Cooling Loop
82-55	30 day	#22 AC Vital Inverter Failed Causing #22 120 V ac Vital Bus to Deenergize
83-01	30 day	Pressurizer Pressure Controller and Shutdown Cooling Loop Return Isolation Valve Inoperable

LER Number	Type	Summary Description
83-02	30 day	ERV-402 Inoperable
83-03	24 hour	AFW valves 4511 & 4512 failed open causing abnormal flow during over-cooling event
83-04	30 day	#22 AFW Pump Inoperable
83-05	30 day	Shutdown Cooling flow lost during Surveillance Testing
83-06	30 day	AFAS Channel ZD for 21 SG level was indicating low
83-07	24 hour	Deenergization of two RPS channels caused the PORV's to open and PZR Quench Tank rupture disk to open
83-08	30 day	#21 Containment Spray Header Inoperable
83-09	30 day	Pressurizer level deviated from program band by more than ±5% several times and Pressurizer pressure decreased below 2225 psia once
83-10	30 day	AFAS Channel ZF Setpoint for Steam Generator delta pressure out of specification
83-11	30 day	#12 Diesel Generator Inoperable
83-12	30 day	Twice during past 30 days, dose equivalent I-131 exceeded 1.0 micro-Ci/gram
83-13	30 day	#21 Emergency Diesel Generator Inoperable
83-14	30 day	Pressurizer level decreased below 133 inches twice within 30 days
83-15	30 day	Linear Heat Rate Alarm detectors Inoperable
83-16	30 day	#21 Diesel Generator Inoperable

LER Number	Type	Summary Description
83-17	30 day	#21 Waltwater Loop Inoperable
83-18	30 day	HPSI header Inoperable
83-19		Cancelled
83-20	30 day	Exhaust damper to 21 ECCS Room Exhaust Fan disconnected from actuator and in shut position
83-21	30 day	Containment Sump Alarm Inoperable
83-22	30 day	AFAS Channel ZF setpoint for steam generator delta pressure out of specification in nonconservative direction
83-23	30 day	Containment Gaseous and Particulate Monitors Inoperable
83-24	30 day	#22 Charging Pump Discharge Relief Valve Inoperable
83-25	30 day	Saltwater Inlet Valves to Circulating Water Pump Room Air Coolers were open while autc SIAS signal was disabled
83-26	30 day	No. 21 MSIV stroked shut in 3.62 seconds, exceeding 3.6 second limit of T.S.
83-27	30 day	Power Dependent Insertion Limit for Group 5 Rods Inoperable
83-28	30 day	No. 12 Accumulator on 21 MSIV Inoperable
83-29	30 day	Dose Equivalent I-131 was 1.38 micro-Curies Per Gram
83-30	30 day	Pressurizer Pressure decreased to 2185 psia; Pressurizer Level decreased to 128 inches
83-31	30 day	No. 21 Containment Cooler Inoperable
83-32	30 day	MSIVs increased to 554.8 Degrees F

LER Number	Type	Summary Description
83-33	30 day	Fire Detection Instrumentation in Containment South East Electrical Penetration Area Inoperable
83-34	30 day	Containment Atmosphere Particulate Radioactivity Monitoring System Inoperable
83-35	30 day	One Main Steam Supply Valve to steam driven AFW Pumps failed open causing #21 AFW Pump to start
83-36	30 day	Reactor Trip Circuit Breakers and Undervoltage Devise Response Time Slower than Allowed by TS
83-37	24 hour	ECCS Pump Room Exhaust Ventilation Systems Inoperable
83-38	30 day	Following Reactor Trip Dose Equivalent I-131 was 2.03 Micro-Curies Per Gram
83-39	30 day	Main Steam Supply Valve to Steam Driven AFW Pumps Failed Open Causing #21 AFW Pump to Start
83-40	30 day	Failure in Turbine Control Circuitry Caused Closure of Main Turbine Governor Valves to Exceed TS
83-41	24 hour	Malfunction in Main Turbine Control Circuitry caused Closure of Intercept and Governor Valves; Reactor Trip on High Pressurizer Pressure
83-42	30 day	#22 Feedwater Regulating Valve Stroked too Slow causing Rapid Filling of #22 Steam Generator
83-43	30 day	Steam Generator Safety Valve Indication Inoperable
83-44	30 day	AFW Flow Indication to #22 Steam Generator Inoperable
83-45	24 hour	Penetration Room Exhaust Fans' Discharge Dampers Inoperable

LER Number	Type	Summary Description
83-46	30 day	#21 Penetration Room Exhaust Fan Inoperable
83-47	30 day	ZA Logic Actuation Occurred Deenergizing 21 4KV Bus Resulting in Loss of #21 LPSI Pump and Loss of Shutdown Cooling
83-48	30 day	#21 Hydrogen Recombiner Inoperable
83-49	30 day	Pin Hole Leak in Reactor Coolant Charging Line Weld
83-50	30 day	Main Steam Valve to Steam Driven AFW Pumps Inoperable
83-51	30 day	Following Reactor Trip Dose Equivalent I-131 was 1.05 Micro-Curies Per Gram
83-52	30 day	AFW Pump Inoperable
83-53	30 day	Fuse Replacement Blew Causing 21 Containment Cooler to Trip