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REGION I

Report No. 50-317/85-03

Docket No. 50-317

License No. DPR-53 Priority -- Category C

Licensee: Baltimore Gas & Electric Company

P.O. Box 1475

Baltimore, Maryland 21203

Facility Name: Calvert Cliffs Nuclear Power Plant, Unit 1

Inspection At: Lusby, Maryland

Inspection Conducted: March 4-15, 1985

Inspectors: Jin W. Chung 7-9-85
Jin W. Chung, Lead Reactor Engineer, Team Leader date

Jin W. Chung for 7-9-85
N. J. Blumberg, Lead Reactor Engineer date

J. Durr for 7/9/85
F. P. Paulitz, Reactor Engineer date

J. Durr for 7/9/85
J. S. Hodson, Reactor Engineer date

Approved by: Stewart D Ebneter 7/9/85
S. D. Ebneter, Director, Division of Reactor Safety date

Inspection Summary: Inspection on March 4-15, 1985 (Report No. 50-317/85-03)

Areas Inspected: Special unannounced inspection of equipment and activities identified in the Calvert Cliff probabilistic risk assessment dominant sequences as important to prevent or mitigate severe accidents. More specifically, selected equipment and activities related to the 125 VDC Bus No. 11; reactor protection system (RPS) trip breakers; auxiliary feedwater system; salt water system; component cooling water system; primary and secondary heat removal systems; and licensee administrative controls were inspected. The inspection included 351 inspector-hours on-site, 10 hours off-site and 10 hours at the NRC regional office by four region-based inspectors.

Results: Violations - None; Deviations - None

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EXECUTIVE SUMMARY

The Probabilistic Risk Assessment (PRA) study (NUREG/CR-3511) conducted on the Calvert Cliffs Nuclear Power Plant Unit 1 (CC-1) as part of the Interim Reliability Evaluation Program (IREP) provided insights into the plant susceptibility to accidents and identified the key components/events that contribute to the core melt frequency. Maintenance of several key components was found to be a significant contributor to certain sequences. Additional insights related to plant operations were that operator errors made during the course of an accident were significant and that operator recovery actions were very important in mitigating accidents. The insights and the details of two dominant sequences from the CC-1 PRA were utilized to develop and conduct an inspection at CC-1 which addressed equipment availability and plant staff recovery actions.

OBJECTIVE

An inspection was performed at CC-1 to assess: 1) the availability of selected equipment identified as important to prevent or mitigate two accident sequences and 2) the ability of the plant staff to effectively respond to and/or recover from the accident sequences.

METHODOLOGY

Probabilistic Risk Assessment (PRA) Driven

The Calvert Cliffs PRA, NUREG/CR-3511 was the driver of this inspection in that it focused inspection activities on those systems/components important to plant safety from a risk standpoint. Further, it more specifically defined activities that the plant staff must perform, in terms of equipment, to mitigate the effects of the event. This aspect allowed the inspectors to evaluate recovery ability and indirectly assess the effectiveness of plant procedures and training programs by simulating recovery activities.

Two accident sequences from the list of dominant accident sequences in NUREG/CR-3511, Interim Reliability Evaluation Program: Analysis of the Calvert Cliffs Unit 1 Nuclear Power Plant (IREP), were analyzed to identify equipment required to prevent/respond to the initiation and the sequence of the events. These sequences also identified important plant operation activities that must be successfully accomplished to prevent propagation of and/or to mitigate the event.

Equipment Availability

The inspection focused on the availability of plant equipment, i.e., were plant programs, such as preventive maintenance, surveillance tests, and configuration control (jumpers and tagging) implemented to a degree which would provide assurance that the selected equipment was available, or in a state of readiness, and could perform its safety function if called upon? This was ascertained by

review of surveillance and maintenance procedures for adequacy, review of plant records related to maintenance and surveillance to assure implementation of requirements, plant hardware inspections to assess equipment status, and inspection/witness of tests-in-progress.

Recovery Actions

To assure plant risk is minimized, a high degree of equipment availability must be complemented by the ability of the plant staff to respond and recover from event initiators and sequences. This latter aspect was inspected by performing a review of plant procedures (operating, emergency and administrative), conducting interviews of plant staff to ascertain familiarity with plant procedures and equipment, and performing "walkthroughs" of recovery actions with plant staff as part of the simulation of the response of plant staff to the sequence identified items.

PRA Sequences

The two sequences chosen from the IREP report were:

Sequence T_{dc}82 (TDCL)

A failure of the DC bus 11 (T_{dc}) results in trip of units 1 and 2, failure of the Power Conversion Systems (PCS) and Auxiliary Feedwater (AFW) pump 13 with degradation of safety systems.

The sequence frequency is estimated as 2.1E-5/yr and contributes 16% of the total core melt frequency. The dominant contributors to this sequence are single failures in the AFW turbine-driven pump no. 11 train combined with failure of the operator to start the locked-out turbine-driven AFW pump no. 12.

Sequence S^2-50 (S^2H)

In this sequence, a Small-small LOCA (S_2) occurs followed by successful scram and operation of AFW and High Pressure Safety Injection (HPSI) providing both secondary heat removal and primary system makeup. When the Refueling Water Tank (RWT) depletes and switchover to recirculation occurs (anywhere from 4 to 12 hours into the transient depending on the size of the leak), the High Pressure Safety Recirculation (HPSR) (H) fails.

The sequence frequency is estimated as 1.4E-5/yr and contributes 11% of the total core melt frequency. The dominant contributors to this sequence are of two types: (1) failures of High Pressure Safety Recirculation (HPSR) pump no. 13 combined with failures of room cooling to the other two HPSR pumps (they are in the same room and failure of room cooling results both pumps failing) or (2) failures of the Component Cooling Water (CCW) system or Salt Water System (SWS) resulting in loss of pump seal cooling and failure of all HPSR pumps.

Inspection Features

The inspection was conducted by a multidisciplinary team of four (4) engineers with extensive experience in the design, maintenance, and inspection of nuclear power plants. The NRC staff utilized licensee staff to perform simulated responses and "walkthroughs" of required operations. Objective evidence to verify equipment availability was obtained by interviews, records review, time line analysis and physical plant inspections.

FINDINGS

The inspection results basically were positive in that those programs designed to assure hardware availability were adequately implemented for the equipment inspected and the plant staff exhibited excellent knowledge of plant procedures and systems.

The physical plant was well maintained and cleanliness and housekeeping were at a high level. The equipment identified by the IREP sequences, in general, was found to be included on the "quality" list and was subject to preventive maintenance, surveillance test and environmental qualification oversight where applicable. The inspectors found that the equipment identified in the IREP sequences was essentially controlled to "safety related" standards via inclusion on the "Q" list. This fact indicates that PRA results have a solid regulatory basis and can be used to drive inspections of high risk systems without substantial fear of encountering wide spread "back fit" issues.

The plant staff, during simulated responses to events/activities readily demonstrated their knowledge of procedures, physical locations of equipment and familiarity with overall plant operations by effectively "walking through" the simulated events. Their responses were indicative of the effectiveness of training on procedures and equipment.

The inspectors did not identify any regulatory compliance issues but did make observations in the following areas.

Human Factors

- Equipment Identification

  The plant generally exhibited excellent plant and equipment designation by color code, alpha-numeric identification, and schematics. In addition, plant areas exhibited information, precautions, and signs, related to fire doors and security zones.

  The following exceptions to the above were observed:

  -- Four 480 Volt feeder breakers in a Motor Control Center were not identified by their equipment numbers.

  -- Motor-driven AFW pump no. 13 was not identified consistent with the other pumps and plant practices.

-- Even though the pumps and other equipment were clearly identified in the ECCS pump rooms, the room identification was not posted on the doors to identify the Unit 1 ECCS pump room from Unit 2. During a routine inspection action with a licensee operator, the operator entered the Unit 2 ECCS pump room instead of the Unit 1 room by mistake.

• Potential Event Initiation by Human Error

A reserve battery system surveillance test required to be conducted per procedure STP-55.0 has the potential to cause the loss of the d-c bus thus initiating the event leading to dominant sequence T_{dc}-82. The surveillance test requires the plant staff to install temporary jumpers on a live bus. During witness of this activity, the inspector noted that the plant staff had difficulty with this task due to size and bulkiness of the cables. The potential exists for the cable to disable the line bus and initiate "Loss of 125 VDC Bus No. 11" event. NOTE: Licensee Quality Circle group had also identified this potential problem at a meeting on December 5, 1984.

Equipment Instability

There were two cases of potential equipment instability that could impact on the ability of hardware to respond during an event. The licensee was aware of both of these but the staff had concerns as noted below.

• Auxiliary Feedwater (AFW) Pump No. 13

The motor driven AFW pump no. 13 was incorporated in the plant several years ago to provide diversity and margin for AFW. However, the motor driven system has a history of flow instability when tested at low steam generator back pressures. This problem was identified previously by the licensee and some corrective actions, which have not completely resolved the problem, have been taken. Also, the licensee has identified additional corrective actions which can resolve the problem. The NRC staff has a concern about the delay in corrective measures which will correct the conditions. The licensee stated that the contributing factors were the delay in procurement of the necessary parts and the difficulty in performing adequate tests at low pressure while the unit is at power. The licensee committed to perform additional corrective actions which will further alleviate the flow instability problems during the scheduled outage in April, 1985 for Unit 1.

• Turbine Driven Auxiliary Feedwater Pump Room Temperature

The design basis study in the FSAR specified that the ambient environment of the room housing the turbine driven AFW pumps be maintained below 130°F to 1) assure the temperature of the pump air-cooled bearing does not overheat and 2) prevent exceeding the environmental qualification of the instrumentation located in the room.

In the event of loss of normal ventilation systems, the emergency fans alone may not maintain the room temperatures within the required 130°F limit. The required temperature limit can only be met with the emergency ventilation system if the AFW room doors which connect to the main turbine bay area are opened in order to allow circulation of cool air through the room. This was not incorporated into the station emergency procedure although the auxiliary operator involved in the simulation was aware of the required action.

Post Maintenance Testing

Subsequent to performing maintenance of the reactor protection system (RPS) trip breakers, the breakers are bench tested by the licensee. Post maintenance in-place tests were not performed per instructions. There is a significant non-conservative difference in observed trip times between bench tests and in-place tests.

CONCLUSIONS

- The inspection staff did not identify any regulatory issues.
- The use of PRA identified accident sequences to guide the inspections focused the attention of the staff on the equipment and activities important to plant safety from a risk standpoint.
- The NRC staff's conclusion was that the plant equipment was in a high state of operational readiness and could be relied upon to respond to initiating events.
- The NRC staff concluded that the licensee plant staff was well qualified and, with a high probability, could recover from accident initiators.
- The licensee could improve his ability to respond to events by taking prompt corrective action to remedy the staff observations discussed in the Findings paragraph above.

DETAILS

1.0 Persons Contacted

Baltimore Gas & Electric Company - Calvert Cliffs Site

C. Behnke, Engineering Technician
D. Buffington, Electrical Quality Control Inspector
J. Carberry, Assistant General Supervisor - Maintenance
E. Campo, Electrical, I&C Quality Control Supervisor
E. Chrzanowski, Nuclear Operation Instructor
M. Cox, Turbine Building Operator
J. Crunkleton, Staff
J. Deck, Electrical Maintenance Unit 1 Supervisor
#*R. E. Denton, General Supervisor - Training & Technical Services
D. Dodson, Control Room Operator - Procedure Development
J. Ecker, Electrical Quality Control Inspector
C. Farrow, Auxiliary Building Operators
M. Graham, Electrical Maintenance Unit 1 Senior Electrician
*R. Heibel, General Supervisor - Operations
D. Holba, Plant Watch Supervisor
R. Howarth, Control Room Operator
J. Lemons, Production Maintenance Superintendent
D. Michel, Electrical Maintenance Unit 1 Senior Electrician
*M. J. Miernicki, Principal Engineer - Operator Licensing & Safety
R. Mondulick, Instrument Preventive Maintenance Unit 1 Supervisor
*J. M. Moreira, General Supervisor - Electrical & Controls
R. Nelson, Electrical Maintenance Unit 2 Senior Electrician
*P. Pieringer, Senior Engineer - Operations
T. Pilkerton, Senior Mechanic
K. Riggleman, Electrical Maintenance Unit 2 Supervisor
*M. E. Roberson, General Supervisor - QA
#*L. B. Russel, Plant Superintendent
R. Sheranko, General Supervisor - Maintenance & Modifications
J. Shoolcraft, Instrument Corrective Maintenance Unit 1 Supervisor
J. Sites, Instrument & Electrical Maintenance Unit 1 Assistant General Supervisor
*R. M. Somers, Senior Engineer - Operator Licensing & Safety
R. Snyder, Electrical & Control Engineering Supervisor
B. Tailley, Plant Operation Instructor
W. Thomas-Azup, Control Electrician Unit 2
*J. A. Tiernan, Manager - Nuclear Power
F. Weekly, Electrical Maintenance Unit 1 Senior Electrician
J. Yoe, Nuclear Operation Senior Instructor

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*T. E. Murley, Region I Administrator
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*K. Murphy, Technical Assistant, Division of Reactor Safety, Region I
T. Foley, Senior Resident Inspector, Calvert Cliffs
#*D. C. Trimble, Resident Inspector, Calvert Cliffs

The inspectors also held discussions with other licensee employees during the inspection, including operations, technical supports, and administrative personnel.

#Denotes those present at the preliminary-exit meeting on March 8, 1985

*Denotes those present at the exit meeting on March 15, 1985.

2.0 Scope of Inspection

2.1 Objective

The inspection objectives were to apply the results of the site-specific PRA study to the inspection program in order to evaluate the availability of the plant systems, components and activities. Also, potential human or operational errors were evaluated to assure the readiness and the effectiveness of the recovery actions to mitigate the events and terminate the sequences before the end point would be reached.

2.2 Inspection Methodology

The methodology employed a two step approach of 1) selecting the items to be inspected and 2) the inspection method or rationale.

2.2.1 Inspection Items

The Calvert Cliffs IREP study (NUREG/CR-3511) was a probabilistic assessment of the plant-specific risks, and provided information on the potential accident risks and insights into the plant design and operation.

The Calvert Cliffs Unit 1 IREP study identified the severe accident sequences which could result in a reactor core melt, and the dominating events were listed by their core melt frequencies. Furthermore, each accident and its sequence identified the specific plant features and activities relative to the initiating top event, preventive and success features (reactor scram and secondary cooling), core melt contributing factors, and recovery actions required to mitigate the accident.

The PRA then, identified high risk components and recovery actions that are interrelated and are important to plant safety. Thus, the PRA output was the driver of the inspection and directed the inspectors to those plant specific items of highest importance.

Two accident sequences were selected, which contributed a combined core melt frequency of 27% of the total events analyzed in the IREP study.

a. Loss of 125 VDC Bus No. 11: TDC-82 (TDCL)

A failure of DC Bus 11 results in a trip of Units 1 and 2 and failure of the Power Conversion System (PCS) with degradation of the safety systems. The plant scrams successfully, but AFW subsequently fails. Containment Air Recirculation and Cooling System (CARCS) and Containment Spray System Injection (CSSI) succeed and cool the containment. As a result of the lack of secondary heat removal, the core inventory boils off through the cycling opening of the PORVs. No credit is given for "feed and bleed" due to the low head of the HPSI pumps and the uncertainty as to whether or not the pressure could be reduced enough for the HPSI pumps to inject water. Recent calculations done by EG&G for the Station Blackout Program indicate that approximately 86 minutes is available to start an AFW pump in order to prevent core uncovering.

The sequence frequency is estimated as 2.1E-5/yr and contributes 16% of the total core melt frequency.

b. A Small-Small LOCA S_2-50 (S_2H)

A small-small LOCA occurs followed by successful scram and operation of AFW and HPSI providing both secondary heat removal and primary system makeup. When the Refueling Water Tank (RWT) depletes and switchover to recirculation occurs (anywhere from 4 to 12 hours into the transient depending on the size of the leak), HPSR (H) fails. Due to the lack of primary makeup, the core then uncovers and core melt ensues. CARCS and CSSI succeed and cool the containment. The sequence frequency is estimated as 1.4E-5/yr and contributes 11% of the total core melt frequency.

The most important systems identified by the PRA which are demanded frequently to mitigate the accident sequences were AFWS, CCWS and SWS. Plant specifics and activities related to these systems were identified considering the sequence of the events, system operability, nature of the failures and successes, and potential weaknesses.

In addition to the PRA identified systems, one non-PRA system was included in the inspection, the reactor protection system (RPS).

In the analysis of both accident sequences in the PRA, it was assumed that the RPS was actuated and the reactor scrammed successfully. Therefore, the RPS trip breakers were included in the inspection.

Further, "Feed and Bleed" operations which were not included in the event sequence analyses even though the primary and secondary heat removal systems could have contributed significantly in preventing the core melt, were integrated into the overall inspection plan.

A total of 58 plant specific features and activities from seven systems were inspected as summarized in the following:

1. 125 VDC Bus No. 11 (initiator): 4 components
2. Auxiliary Feedwater System (AFWS): 17 components
3. Component Cooling Water System (CCWS): 5 components
4. Salt Water System (SWS): 12 components
5. RPS Trip Breakers: 2 components
6. Primary Heat Removal System (PHRS): 14 components
7. Secondary Heat Removal System (SHRS): 4 components

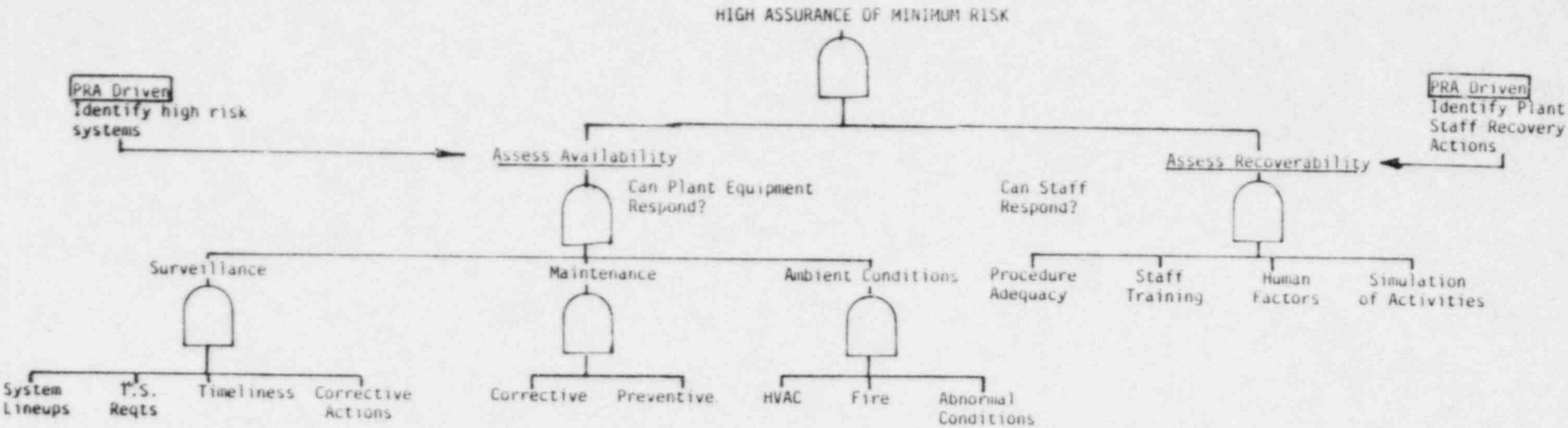
("Component" is the specific plant equipment or operational action identified for inspection.)

2.2.2 Inspection Rationale

The PRA dominant sequences identify an initiating event and the mitigating systems responses required to successfully cope with the accident. From this, specific system components which are required to operate, i.e., be available for system success were identified. The sequence analysis also identified station staff response, i.e., recovery actions, that must be successfully performed to cope with, and prevent propagation of the accident.

The inspection rationale, then, is that the inspection should focus on 1) licensee programs and activities that assure, or contribute to the availability of the equipment required to mitigate accident sequences being reviewed, and 2) the ability of the station staff to effectively perform recovery actions to terminate or mitigate the sequence. See Figure 1.

Equipment availability is basically the ability of equipment to function when called upon to do so, i.e., it is operable. It is affected by aging, environments, operational time/cycles, surveillances and maintenance practices. Therefore, the inspectors reviewed these items to qualitatively judge the availability of equipment.



Inspection Rationale

Figure 1

Recovery actions are those actions the plant staff must take to remove from service equipment that is contributing to the severity of the sequence or the placing in service of redundant or alternate systems to overcome deficient systems. Therefore, the inspectors reviewed plant procedures, licensee training, and equipment/plant features which provide indications of ability to recover.

2.2.2.1 Equipment Availability

The availability (operability) of equipment was evaluated based on the effectiveness of the plant activities which contribute to, or verify, the availability of equipment.

	Plant Features and Programs	Related NRC Inspection Module
--	Preventive and corrective maintenance and their trends	Maintenance
--	Surveillance records and test witnessing	Surveillance
--	Accessibility of the equipment and alternate operations	Independent Inspection
--	Visual inspections	Operation
--	Component cooling, electrical supports, and ventilation	Operation/ Surveillance/ Maintenance
--	Environmental Qualification	Maintenance/E.Q.
--	Potential fire sources/prevention	Fire
--	Calibration	Calibration
--	Procedures	Procedure/Maintenance/Calibration
--	Alarms and indications	Operation

The trending of equipment repairs included qualitative evaluation of the surveillance and maintenance records, and engineering evaluations. Environmental effect evaluations were based on qualitative observations of the effects of salt water, adequacy of cooling, room humidity and temperature effects. The equipment operability evaluation included demonstration of local operations, accessibility of the equipment and emergency lighting.

2.2.2.2 Recovery Actions

The operational readiness and the effectiveness of recovery actions were evaluated based on the ability of the plant staff to respond to and to recover from the accident sequences. This was evaluated based on the inspection of the plant activities as follows:

Plant Features and Programs	Related NRC Inspection Module
-- Procedures: normal, abnormal and emergency	Procedure
-- Demonstration of equipment operability	Operation/Surveillance/ Maintenance
-- Simulation of operations	Operation/Independent
-- Test witnessing	Surveillance
-- Operator Interviews & system walk-through	Operation
-- Training & qualification	Training
-- Operator alertness & human factors engineering	Operation/Independent

2.3 Other Aspects

Throughout the inspection, the potential for a fire as a common mode contributor to equipment failure was considered. The fire inspection included combustibles, fire detectors, potential fire sources and protection systems. Attention was given to potential fire causes such as: electric shorts, ground wires, circuit boards, open circuit, temporary test jumpers and cables, improper wiring, poor ventilation and mechanical overheating.

The programmatic aspects of the plant activities were evaluated in terms of effectiveness of the administrative controls and QA/QC. This included documentation, tagging and housekeeping.

2.4 Procedures

The plant procedures were reviewed to verify that they were consistent with the design features, "as-built" and "as found" conditions, drawings, applicable license requirements, and to ascertain that they were technically correct and adequate to perform the intended functions. The procedures reviewed included:

- -- Normal, abnormal, alarm response and emergency operating procedures
- -- Surveillance procedures,
- -- Corrective and preventive maintenance procedures and applicable vendor manuals or specifications,
- -- Applicable administrative control procedures, and
- -- Training procedures.

2.5 Records

It was desirable to review as many records as possible, particularly for corrective maintenance activities and trend evaluation of component repair and wear. The plant records reviewed included:

-- Surveillance test records,
-- Preventive maintenance cards,
-- Post-maintenance and functional test records, and
-- Selected operational surveillance checks.

Other supporting documents were reviewed to achieve the inspection objectives. They included:

-- Plant Piping and Instrument Drawings (P&ID),
-- QA/QC manuals,
-- Plant "Q" list manual,
-- Applicable LERs,
-- System Descriptions and FSAR
-- Environmental Qualification Reports and Deficiency Reports.

3.0 125 Volt DC Bus No. 11 - Assessment of Accident Initiator

The failure of 125 Volt DC Bus No. 11 was identified as an initiating event of one accident sequence. Bus No. 11 and associated components were evaluated to assess potential sources of bus failure. The inspection effort focused on the availability of the battery, battery chargers and distribution bus.

3.1 System Description

The 125 volt DC system provides continuous power for control, instrumentation, reactor protection, and engineered safety features actuation systems (ESFAS). Also, it provides control power to the emergency AC circuit breakers for the 4160V switchgear, and powers the control valves in the auxiliary feedwater systems (AFWS). The 125 vdc system is normally powered from the AC system via four battery chargers.

The 125V DC and 120V AC systems for both Units 1 and 2 are divided into four independent and isolated channels. Each channel consists of one battery, two battery chargers (one per each unit), one DC bus, multiple DC unit control panels, one inverter per unit (total of two) and one 120V AC vital instrumentation and control bus per unit (total of two). The station batteries and/or the battery chargers supply power to the DC bus, DC unit control panels, and inverters.

The 125 volt DC buses nos. 11 and 21 feed the majority of DC equipment, including the control power for the time channels of the switchgear throughout the plant auxiliary system. Failure of either of the DC buses causes a plant trip and safety system degradation. If 125V DC bus no. 11 fails, all standby safety systems--one half of all systems--will be affected such as the auxiliary feedwater system (AFWS), high pressure safety injection (HPSI), low pressure safety injection (LPSI), containment spray system injection (CSSI), and a motor-driven AFW pump (no. 13). In addition, the 120 volt AC bus no. 11 will fail as a result of the DC bus no. 11 failure, causing failures of a steam generator (SG) level control, various instrumentation and a SG feedwater pump recirculation line valve.

3.2 Inspections to Assess Availability

3.2.1 Visual Inspection

The following plant areas and components of the 125 vdc bus were inspected:

- Battery Room No. 11
- Battery Room No. 11
- Battery Changers
- DC Distribution Bus

Visual inspection of these areas assessed general condition of the equipment, as-built location, proper identification, ambient environmental conditions, accessibility for maintenance, and station administrative controls related to housekeeping and fire prevention.

3.2.2 Surveillance Test and Simulation of Activities

The inspector witnessed licensee performance of surveillance tests related to the battery to verify compliance with T.S. requirements and procedural controls. Test witnessing also provided a performance based assessment of station personnel training and competency.

The NRC staff observed licensee staff performance during simulation of emergency maintenance activities and recovery actions identified in the PRA. Licensee staff utilized station equipment and procedures in a "walkthrough" of the maintenance/ recovery actions. NRC staff assessed ability to perform the action and identified potential problems, such as accessibility, and adequacy of the recovery sequence.

3.3 Document Review

The following documents were reviewed to determine that operation, inspection, test, preventive maintenance and corrective maintenance activities were being conducted in accordance with the commitments of the Final Safety Analysis Report (FSAR) and the requirements of the Quality Assurance Program and Technical Specifications.

Final Safety Analysis Report

Section 8.4.2, Station Control Batteries, Revision 3,

Technical Specifications

Electrical Power Systems Surveillance Requirements, Amendment 92, Sections 4.8.2.3.1 and 4.8.2.3.2.a thru f.

Operation Instruction (OL)

OI-26A, 125 Volt Vital DC, Revision 9.

Surveillance Test Procedure (STP)

-- STP 0-90-1, Breaker Line Up, Revision 7 (Weekly) Observed on 3-12-85

-- STP M-150-1, Station Battery Check, Revision 0 (Weekly) Battery 11-12-01. Dated 3-13-85

-- STP M-350-1, Station Battery Check, Revision 0 (Quarterly)

-- STP M-550-0, Battery Inspection and Service Test, Revision 5 (18 months)
  - o Battery 11. Dated 9-24-84

-- STP M-551-0, Battery Charger Operability, Revision 2 (18 months)
  - o Battery Charger 14-22 Dated 11-6-84, Test Out of Spec.
  - o Battery Charger 14-22 Dated 11-9-84, After Maintenance
  - o Battery Charger 13-21 Dated 11-5-84, Test Out of Spec.
  - o Battery Charger 13-21 Dated 11-5-84, After Maintenance

-- STP M-650, Performance Test of Battery Capacity, Revision 0 (60 months)
  - o Battery 11. Dated 10-01-79
  - o Battery 12. Dated 11-03-79
  - o Battery 21. Dated 11-07-79
  - o Battery 22. Dated 11-10-79

Preventive Maintenance (PM)

-- PM 1-2-E-R-1 125 Volt DC Busses Battery Chargers Over and Under Voltage, Revision 1

-- PM 1-2-E-A-1, 125 Volt DC Busses 480 Volt Feeder Breakers and Battery Chargers 11-12-13-14, Revision 1

Corrective Maintenance-Maintenance Request (MR)

Maintenance records reviewed are listed in Attachment.

3.4 Findings

3.4.1 Visual Inspection, Surveillance Test and Simulation Activities

During the simulated "walkthrough" of maintenance and recovery activities, the inspector identified a condition that potentially could actually initiate the event-loss of 125 vdc bus No. 11.

The following activities involve the use of temporary cables:

- Battery No. 11 Removed from Service
- Battery No. 11 Load Test
- Battery No. 11 Recharge after Test
- Battery No. 11 Return to Normal Condition
- Possible Temporary Hookup During Accident Conditions (Recovery)

The temporary cables are very bulky, heavy, and difficult to manipulate. Maintenance personnel had great difficulty in handling the cables. It was observed that there was a potential for the cables to short out the d-c bus thus disabling it and initiating the event of loss of 125 vdc bus.

During the exit interview, the CC Maintenance Manager noted that the CC quality circle had identified the potential for technical problems and personnel safety concerns. This was documented in the December 1984 quality circle meeting minutes.

No violations of license conditions or other deficiencies were identified in equipment operation; equipment condition; electrical hazards; fire detection and protection; potential combustible material not previously identified; security; and housekeeping.

3.4.2 Maintenance Review

Document review for battery no. 11 system operation, surveillance and maintenance indicated that the service and performance test were conducted at the proper intervals in accordance

with the Technical Specification. It also indicated that the electrolyte level was maintained between maximum and minimum levels by adding water, and the float voltage was maintained.

There were nine maintenance requests (MRs) in one year to remove either a positive or negative ground condition on battery no. 11 bus. These ground conditions if not removed may cause a unit trip or failure of the system. A plant maintenance procedure was used for temporary isolation of feeders from bus no. 11. This procedure, Battery-7, Revision 0, dated January 13, 1982 requires the use of temporary cables to connect the reserve battery system via the reserve battery circuit to six distribution panels. This provides power to the circuits when the disconnect to the panels from bus no. 11 was opened and isolated the ground from bus no. 11. The precaution listed in the procedure indicated the potential for personnel injury and equipment failure when troubleshooting for battery grounds.

The degree of difficulty of locating a ground condition was indicated in Maintenance Request 0-83-08197. The work was started at 1250 hour on 11-30-83 and was not completed until 0800 hour on 12-2-83. The ground was located on MTSV-A position switch.

3.4.3 Summary

No violations of license conditions or deficiencies were identified. Within the scope of this inspection, it is concluded that the vital DC bus no. 11 and associated batteries and chargers would be available for operation if called upon.

Based on the visual inspections, observation of surveillance tests, simulated walkthroughs, and review of maintenance activiites, it is concluded that the battery system has been installed and maintained in a reliable manner. The following activities could result in potential failure of the bus or personnel injury or both.

-- The use of temporary cables for battery maintenance or load test.

-- The method and use of temporary cables to detect battery grounds.

The above two items collectively constitute an unresolved item, (317/85-03-01).

4.0 Reactor Protection System (RPS) Trip Breakers

In the selected accident sequences, successful reactor scrams were assumed upon initiation of the events. The RPS breakers were evaluated to assure that the reactor would trip by opening the breakers when such action was called for. This evaluation was included because of the recent NRC concerns related to ATWS events.

4.1 System Description

The Reactor Protection System is composed of input from eleven plant process variable instruments. These plant process variables are input to the four channels A, B, C, and D. Any two out of four channels will deenergize the following control relays, which in turn trip the reactor trip breakers:

Control Relay	Reactor Trip Breaker	
K1	RTB-1	RTB-5
K2	RTB-2	RTB-6
K3	RTB-3	RTB-7
K4	RTB-4	RTB-8

The reactor may be tripped by any one of the following abnormal conditions:

-- Open the 480 volt supply breakers to both motors of the Motor-Generator (MG) sets.

-- Failure of the electrical supply to the above motors.

-- Open the 240 volt output breakers from the generators of the motor-generator sets.

4.2 Inspections to Assess Availability

The objective of this assessment was to determine the reliability of the reactor trip function based on a review of the trip breakers. Thus, it is assured that the desired event, trip, occurs when required and prevents initiation of potential undesired events.

4.2.1 Visual Inspection

The inspector visually inspected the trip breakers, enclosures and ambient environment. Breaker location, general conditions, breaker position and tagging, and identification were verified. Individual breakers and control relay calibrations were verified. The enclosures and equipment room cleanliness, access and local environment conditions were noted.

4.2.2 Surveillance Test and Maintenance Activities

The inspector observed maintenance to replace Unit 2 breaker RTB-5 and RTB-2 front assemblies. In addition, maintenance activities related to closing coil replacement and internal wiring were observed and inspected.

Subsequent to the maintenance, the inspector observed breaker installation and verified operation of the breaker by trip from the local position and also from the control room. A bench test for trip response time was conducted on this breaker; however no in-place functional test was performed (see Findings).

4.2.3 Design Features

The reactor trip system design incorporates redundancy in several ways; of interest to this inspection was the breaker trip features. The inspector reviewed the breaker design and verified that the trip signals activate both the shunt and undervoltage trip mechanisms on the breaker thus providing high reliability of trip.

The design also incorporates features to trip the breakers from the control room and local position.

To assure that the reactor has tripped when a Reactor Protection System trip signal has been received, procedure EOP-1 requires that the control room reactor trip buttons be depressed (manual reactor trip). If the reactor has not tripped the procedure then requires that the CEDM MG sets be deenergized by opening the feeder and the breakers to 480 volt BUS 12A and 480 Volt BUS 13A located in the Control Room.

Each set of two breakers can be locally tripped by a single trip button. Each individual breaker has its own mechanical trip. The 1C86 CEDM MG set motor control panel is in the switchgear room one level below the control room, and both CEDM MG sets can be deenergized from this panel. No. 11 MG set breaker can be opened locally.

The No. 12 CEDM MG set and the K87 MG set control panel are located in the switchgear room adjacent to the control room. Both MG sets can be de-energized from this panel, and No. 12 MG set outbreaker could be opened.

Design features provide redundant indications in the control room to assure operators can positively determine that trip has occurred.

There are several means in the Control Room to assure that the reactor has tripped. Control panel 1C05 has two manual reactor trip buttons which should assure all trip breakers will open. A second set of manual reactor trip buttons are located on Reactor Protection System Panel 1C015. Control Panel 1C17 contains the 480V tie and feeder breakers which will trip the CEDM MG sets.

In addition to normal plant parameters which provide indications that the reactor has tripped, the following indications are available to assure that all rods have tripped:

-- Rod bottom lights for each rod
-- Metroscope for a visual indication of each rod position
-- Metroscope repeater digital readout of rod positions
-- Control rod group position indicators.

4.2.4 Simulation of Activity

Procedure EOP-1, "Reactor Trip", is the Calvert Cliffs emergency operating procedure for operator actions following an automatic reactor trip or reactor trip signal.

Reactor scram immediate action procedures were discussed with and simulated by two control room operators. The operators were knowledgeable as to required actions and the location of equipment. One of the operators simulated the unit trip from the switchgear room, by locating the reactor trip breakers and CEDM MG set control panels.

If all or a portion of the CEDM's failed to insert after attempts in the control room, the operators would then initiate emergency boration. Attempts to trip any remaining CEDM's using local breakers would take place either concurrently with or subsequent to emergency boration.

Control room operators received extensive training on emergency shutdown of the plant and reactor trip situations. This training was included in lesson plans, simulator training, actual control evolutions or simulations, and the Operations Qualification Manual.

4.3 Document Reviews

License Conditions

-- Final Safety Analysis Report Section 7.2, Reactor Protection System.
-- Technical Specification Section 4.3.1.1.3 Reactor Trip Response Time.

Surveillance Test Procedure

-- STP M-200-2 Reactor Trip Breaker Functional Test Rev. 3, dated 12/17/84, revised interim for response time test in place, date 2/19/85. Test conducted on all Unit 2 breakers, dated 3/4/85.

-- Operation Quality Assurance Surveillance Procedure, Rev. 29.

Preventive Maintenance (PM)

-- PM 1-58-E-Q-1, Reactor Protection System, Revision 2.
-- PM 1-58-E-A-1, Reactor Trip Switchgear.

Corrective Maintenance - Maintenance Request (MR)

Maintenance records reviewed are listed in the Attachment.

4.4 Findings

4.4.1 Operations

No violation of regulatory requirements or other deficiencies were observed. Procedures, backup methods for trip and operator training were adequate. If there are stuck control rods or trip breaker failure, emergency boration can quickly shut down the plant.

4.4.2 Trip Breakers

There was no response time requirement for the reactor trip breaker opening (trip) in the technical specification. As an administrative limit the licensee used 0.200 seconds or less. Prior to February 1985, the trip response time, independent trip verification of the shunt trip and the under voltage trip tests were not conducted with the breakers in their normal operating position. The above tests were conducted with the breaker removed (bench test), and the breaker was tripped prior to removal.

A previous NRC inspection identified the concern that the bench trip response time might be less conservative than the in-place trip response time. The licensee agreed to reduce the acceptable time to 0.100 seconds for the bench test. Since February 1985, the breaker trip response time was verified in place as part of the functional test.

A licensee review of the maintenance requests indicated a history of breaker trip problems. The problems were resolved by replacing the front frame assembly with a new design that applied Mobil 28 lubrication. There have been seven modifications of the Unit 1 reactor trip breakers, involving the replacement of the front frame assemblies. Six of these utilize Mobil 28 lubrication. There have been four modifications of the Unit 2 reactor trip breakers, involving new front frame assemblies. Four of these have Mobil 28 lubrication. The trip response times of these breakers range from 0.040 to 0.072 seconds except RTB-6, which has 0.192 seconds. This breaker was to be modified in March 1985.

The inspector observed that no functional test was conducted on breaker U-2 RTB-2 after installation following modification MR 000737. The licensee agreed to revise the procedure to require an in-place functional test once a breaker is removed from its operating position.

The trip response time of the RTB is based on the auxiliary "A" contact (normally closed) opening for a shunt (energized) trip and the auxiliary "B" contact (normally open) closing time for a under-voltage (De-energized) trip. Since the actual current interruption occurs when the last pole of the three pole breaker opens the licensee was asked to verify this time with respect to the auxiliary contact times. This verification on breaker U-2 RTB-2 was as follows:

-- Last main pole open time 0.038 seconds
-- Shunt trip "A" contact open time 0.040 seconds
-- Undervoltage trip "B" contact close time 0.044 seconds

The use of auxiliary contacts in the determination of RTB response time testing indicated that their times were conservative with respect to the actual breaker pole interruption time.

The breakers were properly identified with name plates, and the work area was conducive to good workmanship. The inspectors verified that instruments used were calibrated. Furthermore, the electrical maintenance personnel doing the modifications were knowledgeable and used approved procedures.

The reactor trip breakers have been maintained in an acceptable manner except the functional tests were not conducted after modifications. When the repaired breakers were installed, the in-place functional tests were not performed by operations. This is a contrary to the station maintenance instruction CCI-200I which addresses post-maintenance testing requirements. When informed of this deficiency, the licensee promptly tested

all breakers and stated that the station instructions would be revised to clarify the post-maintenance testing requirement for all safety-related equipment by June 1, 1985. This is an unresolved item, pending licensee action and subsequent NRC inspection (317/85-03-02).

5.0 Auxiliary Feed Water System (AFW) - Recovery System

The auxiliary feedwater (AFW) system is a significant system in terms of plant response to off normal conditions and recovery. Most of the dominant sequences identified in the PRA include failure of the AFW. The two sequences selected for this inspection, T_{dc} - 82 ($T_{dc}L$) and S_2 - 50 (S_2H), involve the AFW.

5.1 System Description

The AFW system has two steam turbine-driven (T-D) pumps and one motor-driven (M-D) pump for each unit. The T-D pumps feed a common discharge header which normally feeds both steam generators (SG) concurrently. The M-D pump feeds a separate discharge header which also feeds both SGs concurrently. The Technical Specification 3.7.1.2 requires that one AFW pump be aligned for automatic actuation, and the other be on standby and operable but aligned such that it will not start on an Auxiliary Feedwater Actuator Signal (AFAS). To comply with the above, No. 11 AFW pump is aligned for automatic actuation. In addition, the M-D pump is capable of providing AFW cross feed to the other unit.

The six AFW pumps for both units take a common suction on a Condensate Storage Tank (CST) which contains a minimum of 150,000 gallons of water. This is sufficient to cooldown one unit from normal power operating temperature. Two other CSTs, with the same capacity are also available as a backup AFW supply. The T-D pumps receive their steam from the main steam header inside the Main Steam Isolation Valves (MSIVs) and auxiliary steam supply line.

The AFW System can be started manually from the Control Room or in case of Control Room evacuation, it can be operated from the Auxiliary Shutdown Panel located at Elevation 45' of the turbine building. The AFW system will start automatically on an Auxiliary Feedwater Actuation Signal (AFAS) which comes from a SG low level signal. One M-D and T-D pump will start on an AFAS. The second T-D pump is required to be locked out from an AFAS. This is accomplished by locking shut the steam inlet valve to the AFW pump turbine. Although the pump steam supply valve will open automatically on an AFAS, the pump itself will not start. The locked-out pump must be started by unlocking and manually opening the steam inlet valve.

The T-D pumps have pump speed controls which can be operated from the Control Room. In addition, flow to the SG's can be controlled by an air-operated flow control valve in the discharge line to each SG. The M-D AFW pump also has a separate air-operated flow control valve to each SG.

5.2 Recovery Actions Involving AFW

The items underlined in Section 5.1 above were selected for inspection because these items, cross feed operation, startup of a locked out AFW pump, and flow control to SGs all represent operations that may have to be performed during the accident to provide mitigation and/or prevent propagation of the event.

Each of these activities was inspected to verify adequacy of procedures and operational features. The performance of the station staff was evaluated by simulating the activities and walking through the activity in plant areas.

5.2.1 Cross Feed From Unit 2 to Unit 1

5.2.1.1 Procedure

When the Unit 1 auxiliary feedwater is lost, the Unit 2 M-D auxiliary feedwater pump has the ability to supply auxiliary feedwater from Unit 2 to Unit 1. Section V of Abnormal Operating Procedure (AOP)-3D, "Loss of Auxiliary Feedwater", provides a procedure for feeding the steam generators of one unit using the motor-driven auxiliary feed pump from the other unit. Also, blocking valves are closed preventing the AFW pump from feeding both units concurrently.

The AFW system operating procedures were available in the Control Room and in the Turbine Building at the Turbine Building Operator Station. Section 7 of AOP-9, "Alternate Safe Shutdown Procedure/Control Room Evacuation" provides operating procedures for the AFW system from the Auxiliary Shutdown Panel in case of control room evacuation. Cross feeding of the steam generators can be performed from this panel.

5.2.1.2 Operational Features

Sufficient control is provided in the control room to perform cross feeding operations at the control room panel. The operator can shut blocking valves to the steam generators of the unaffected unit, lineup to the affected unit, and operate the appropriate M-D pump. Since this requires equipment operations for both units, close coordination between the operators of each unit is necessary. Both units share the same control room and thus operators from each unit are able to communicate directly. In addition, operators are licensed for both units and rotate their duties between the units so that they are familiar with the equipment and operational considerations of each unit.

Sufficient indications in the control room are provided to monitor the cross feeding, including the steam generator blocking valves, the cross feed valves and other valve positions; pump flow indication for the motor-driven pumps; and steam generator level indication on the normal level channels, the safety channels, and at the AFW panel. Each level indicator has a different source of power.

Should it be necessary to evacuate the control room or if control was lost from the control room, the AFW system can be operated from the Auxiliary Shutdown Panel located in the switchgear room adjacent to the control room. Valve position indications, pump operation, and steam generator level indications are available at this panel. In order to operate from the auxiliary shutdown panel, a key has to be used to transfer the operations from the control room to the panel, and the key is located by the operations shift supervisor station. Also, pump speed control valves in the AFW pump room have to be swapped and a Turbine Building operator must switch control air valves in the Service Water pump room.

If all remote control of the system is lost, such as a loss of control air, then all necessary valves can be operated locally. Each unit cross-connect valve and steam generator blocking valve has a manual handwheel operator. Since both units are involved, coordination would have to be established between valve operations in the Unit 1 and Unit 2 Service Water Rooms where these valves are located. The motor operated AFW pumps can be operated locally from breakers in the switchgear room. All valves are easily accessible.

5.2.1.3 Operational Simulation

The cross feeding procedure, AOP-3D, was simulated from the control room by a control room operator. Based on this simulation, the procedure appeared to be workable. No actual controls were operated, valves and controllers were touched by the operator and their operations were discussed.

Manual operations were simulated using Unit 1 and Unit 2 Turbine Building operators. Procedures were available to each operator at their respective operating stations. Each operator demonstrated satisfactory knowledge of local system operations. All manual valves were located in each Unit Service Water Pump Room, and valve operations were simulated. Once the

need to cross feed from Unit 2 to Unit 1 has been identified, cross feeding using manual operations could be established in approximately ten minutes.

5.2.2 Ability to Start Locked-out AFW Pump No. 12

5.2.2.1 Procedures

No. 12 AFW pump is aligned for standby except locked-closed valve 1-MS-107, "Main Steam Inlet #12 AFW Pump Turbine", which prevents automatic actuation of the pump #12.

Procedure OI-32 provides normal operating instructions for AFW pumps No. 11 and No. 12 alignments but does not provide specific instructions for starting a locked out pump. However AOP-3D, "Loss of Auxiliary Feed", provides a procedure for starting the standby pump by opening the steam supply valve to the standby AFW pump.

Since surveillance test 0-5-1 (0-5-2 for Unit 2), requires operation of each steam-driven AFW pump and is performed once a month for each Unit, turbine building operators may perform the operation of starting the locked-out standby pump as many as twenty-four times a year.

5.2.2.2 Operational Features

Starting of a locked-out pump cannot be accomplished from the control room. Main steam inlet valve to no. 12 AFW turbine, 1-MS-107 (or no. 11 AFW pump turbine, 1-MS-109) must be opened locally in the AFW pump room using the valve handwheel. The valve contains a locking device which can be removed quickly.

A station operator stated that station management was considering changing all locked valves to key lock and chain. For such key lock and chain, assurances would have to be made that Turbine building operators have the means for rapidly unlocking valves which are key-locked shut. The valves are easily accessible in the AFW pump room, and operators obtain plenty of experience in starting the locked-out standby pump by performing procedures 0-5-1 and 0-5-2 at least once per month, as discussed previously.

5.2.2.3 Operational Simulation

Both "day" and "swing" shift operators exercised simulated operations of starting the locked-out pump to demonstrate the operators knowledge. In addition, operators demonstrated the ability to reset a tripped AFW pump turbine.

The AFW pump room has a key card reader lock. When the computer is down the door must be opened manually using a key. For security reasons, keys for this room are not issued to Turbine Building operators. To enter the room, the operators call a security guard or obtain a key from the shift supervisor in the control room. In order to start the standby pump rapidly, entry into the room could be delayed if the plant computer was down.

5.2.3 Ability to Increase AFW Flow to SG No. 11

5.2.3.1 Procedures

AFW steam-driven pumps No. 11 and No. 12 feed both steam generators. To provide flow to SG No. 11 any one or combination of the following methods could be used to achieve additional flow to the generator:

-- Increase pump speed controls for AFW Pumps No. 11 and No. 12
-- Fail open SG No. 11 flow control valve 1-AFW-4511
-- Open flow control bypass valve 1-AFW-163
-- Operate motor-driven AFW Pump No. 13
-- Cross feed from Unit 2 using motor driven AFW Pump No. 23 (see paragraph 5.2.1)
-- Fail open AFW Pump No. 13 flow control valve 1-AFW-4525
-- Open 1-AFW-4525 bypass valve 1-AFW-970
-- Flow Controls to SG No. 12

Not all of the above operations are included in the plant procedures. The need to accomplish any of the above operations would depend on the specific conditions of restricting flow to SG No. 11.

OI-32, "Auxiliary Feedwater System - Unit 1", provides instructions for normal operation of the AFW system, adjusting pump speed and flow control, and placing the motor-driven pump in service. AOP-3D, "Loss of Auxiliary Feedwater", provides miscellaneous checks

for loss of AFW to any SG; and also provides instructions for crossfeeding from Unit 2. AOP-9, "Alternate Safe Shutdown Procedure..." provides instructions for AFW control from the auxiliary Shutdown Panel and provides instructions for AFW pump flow and speed control from this panel. While none of these procedures take into account all of possibilities noted above, they appear to provide an adequate base for operator action.

5.2.3.2 Operational Features

The AFW flow control valves and SG blocking valves are air operated and will fail open on loss of air. Bypass valves for AFW flow control valves are located at elevation 27' in Auxiliary Building East Penetration Room and can be opened manually. These valves are accessible.

The speed control of the turbine-driven AFW pumps can be performed remotely from the Control AFW stations or from Auxiliary Shutdown Panel, and may be adjusted locally at the pump.

5.3 Post Surveillance Test Conditions

In the performance of surveillance tests to verify operability of the AFW system, it is possible to inject personnel error which could degrade, or in some cases make AFW unavailable. The inspectors selected two specific surveillance activities which have this potential, logic reset and AFW pump discharge valve alignment, for inspection.

5.3.1 Reset AFW Pump No. 11 AFAS Actuation Logic After Test

It is essential to assure that logic is reset after surveillance test so that the AFW actuation signal can be transmitted. If reset is not accomplished the logic channel is not available.

5.3.1.1 Procedures

Test Procedure (STP)-0-9-1, "Auxiliary Feedwater Actuation System (AFAS) Monthly Logic Test", provides surveillance procedure of each AFAS logic module. The test permits only one subchannel to be tested at a time. After each logic module is tested a specific step is provided to signoff that the logic module has been reset. At the completion of STP 0-9-1, Step 1 of a return to normal, a signoff is required to ensure that all AFAS test signals are

clear and all AFAS logic modules are reset. In addition, OI-32, Section XII, provides general operating instructions for AFAS. A portion of this procedure provides instructions for returning and resetting the actuation logic cabinets to normal during low steam generator level conditions.

5.3.1.2 Operational Features

AFAS logic panels are located in the AFAS logic cabinet which in turn is located in the 27' Switchgear Room. The logic cabinet and each logic channel is clearly identified. There is a reset button for each logic channel which is also clearly identified. If a logic channel is not reset, an alarm in the Control Room above the AFW control station would be annunciated.

5.3.2 Restore AFW Pump No. 11 Discharge Valve to Open Position Following Test

Proper AFW valve alignment (open) is essential to assure the AFW function can be accomplished.

5.3.2.1 Procedures

AFW Pump No. 11 is tested monthly per procedure 0-5-1, "Auxiliary Feedwater System." During this test the pump discharge valve 1-AFW-103 is required to be closed and upon completion of this portion of the test the valve 1-AFW-103 is locked open. In addition, the procedure requires both a signature verification that the valve has been locked open plus a signature verification of a second check that the valve has been locked open. The valve lineup in OI-32 also requires this valve to be in the locked open position.

5.3.2.2 Operational Features

AFW Pump No. 11 discharge valve is located in AFW pump room in the Turbine Building. The valve is a handwheel operated valve and is readily accessible for operation. Since the two steam driven AFW pumps for each unit are tested monthly, pump discharge valves are operated as frequently as 24 times per year for each unit.

5.4 Test Witnessing

A monthly test is required to demonstrate operability of the auxiliary feedwater pumps, flow control valves, and system cross feed valves. On March 11, 1985, Unit 2 surveillance test 0-5-2, "Auxiliary Feedwater System", was witnessed by members of the NRC inspection team. One

inspector observed plant personnel operating steam-driven AFW pumps in the Unit 2 AFW pump room and another observed control room operations. Although the test was performed on Unit 2, Unit 2 and Unit 1 equipment are identical and the operators performing the test work interchangeably between two units. Therefore, the test results, evaluations of equipment operation, and performance of operators could be extrapolated as an evaluation of Unit 1 within the context of this inspection. Test results (as applicable to cross feeding operations from Unit 2 to Unit 1) indicated proper operability of no. 23 motor-driven AFW pump and valve 1-AFW-4550-CV, No. 13 AFW supply valve to Unit 2 and that the operators were knowledgeable of overall system operation. Data from the previous three months for the equivalent Unit 1 test, 0-5-1, were also reviewed.

The surveillance test and results from these tests indicated:

-- Satisfactory performance of the No. 13 M-D AFW pump and valve 2-AFW-4450-CV, No. 23 AFW pump supply valve to Unit 1;

-- Satisfactory performance of the locked-out standby AFW pump;

-- Satisfactory performance of the T-D AFW pump speed controls from the control room and locally at the AFW pumps no. 11 and no. 12;

-- Satisfactory performance of AFW pump discharge valves 2-AFW-103 and 2-AFW-117 to locked open positions after test.

5.5 Training on AFW Operations

Review of lesson plans, system study guide, and interviews with control room and plant operator instructors indicate operators receive extensive training on the specifics and the operation of the AFW system. Within the last five years, the AFW system has been extensively modified including the addition of one motor-driven AFW pump for each unit and newly installed cross feed piping and valves. The motor driven AFWP gives the ability to cross feed from one unit to the other.

Control room operator training includes cross feeding operation and control of the AFW system using the auxiliary shutdown panel, AFAS actuation logic and resetting of AFW pumps after logic test. Turbine Building operators receive extensive hands-on training on all systems in the Turbine Building including the AFW system. The training includes specific procedures, such as loss of main feedwater, loss of auxiliary feedwater, and operational testing of the AFW system. In addition to the above training, Turbine Building operators receive periodic classroom retraining.

As noted previously, Unit 1 and 2 equipment are identical and therefore, the monthly surveillance tests are repeated as frequently as 24 times in a year and provide operators extensive experience in the operation of the AFWS and its logic.

5.6 Findings

No violations of license requirements or other deficiencies were identified. Procedures, equipment operability, operator knowledge, and training were such that crossfeeding from Unit 2 to Unit 1 Steam Generators could be accomplished.

Operators demonstrated their ability to start a locked-out AFW pump during the simulated operations and were performing the operations routinely during monthly system testing.

Numerous methods are available to increase AFW flow to Steam Generator No. 11. Operators demonstrated overall knowledge of AFW system operation including the ability to adjust pump speed. Although not all methods were simulated or demonstrated, sufficient evidence was observed that the ability to increase flow to SG No. 11 was readily available.

Annunciators in the control room, specific requirements in the test procedure to reset AFAS actuation logic, and signoff verification that the logic has been reset would assure that pump No. 11 actuation logic would be reset after test.

Since procedure 0-5-1 requires that the AFW Pump No. 11 discharge valve be locked open and that this action be double verified and signed for, chances for this valve not to be restored to the locked open position after test are minimal.

During AFW simulations, test witnessing and inspections, the inspectors noted the cleanliness of plant areas and adequate fire prevention.

6.0 Availability of Mechanical Components

6.1 Scope

The review of mechanical components in the auxiliary feedwater system primarily focused on the following components:

a. Turbine-driven auxiliary feedpump No. 11 (including turbine, stop and governor valves)

b. Turbine-driven auxiliary feedpump No. 12 (including turbine, stop and governor valves)

c. Auxiliary feedwater valves

-- 1-AFW-0161, 0162-0164 -- 1-AFW-102, -103 -- 1-AFW-115, -116, -117 -- 1-AFW-191, -192, -193, -194 -- 1-CV4520, 4521
-- 1-CV4511, 4512
-- 1-AFW-129, -130 -- 1-CV4530, 4531

d. Auxiliary feedwater steam valves

-- 1-MS-103 check valve in steam admission line from no. 11 Steam Generator
-- 1-MS-106 check valve in steam admission line from no. 12 Steam Generator
-- 1-CV4070 Steam Admission Valve for no. 11 Steam Generator
-- 1-CV4071 Steam Admission Valve from no. 12 Steam Generator
-- 1-MS-102, -105, -109, -110, -222

6.2 Inspection Activities

Each component was inspected qualitatively to verify that it would not cause loss of system function and that, if challenged, it would perform in accordance with its intended function. Plant hardware and ambient condition inspections were supplemented by review of preventive/corrective maintenance records, review of surveillance test data, and in-service test records.

6.3 Visual Inspection

Visual inspection consisted of an examination of the component and the area around the component. Support systems, such as Heating, Ventilation and Air Conditioning (HVAC) and fire protection/prevention were also examined to verify the following:

- General external condition (damage, corrosion, cleanliness, etc.)
- Local indications of operating status, if applicable
- Oil leaks, if applicable
- Oil levels in reservoirs, if applicable
- Steam or water leaks
- Sources of combustion in area
- Fire protection/prevention systems
- Environmental conditions (temperature, humidity, etc.)
- HVAC systems (adequacy of ventilation)
- Potential system interaction with Non-Q Systems

6.3.1 Turbine-Driven AFW Pumps No. 11 and 12

Turbine driven AFW pumps No. 11 and 12 were visually inspected, and no external damage, cleanliness problems or indications of major steam/water or oil leaks were observed. For the pumps, turbine drivers, stop and governor valves, bearing oil level, which can be observed locally, were satisfactory. Combustion sources in the area were limited to the relatively small amount of lubricating oil. Fire prevention/protection was provided by a ceiling smoke detector and a water spray system. Room cooling was provided, when required, by the normal Ventilation System using service water as a cooling medium and the Emergency Ventilation System. Room cooling and potential problems associated with the room cooling are discussed in greater detail in section 6.7. Potential interactions with Non-Q systems were observed to be minimal since the T-D AFW pumps are located in a dedicated pump room.

6.3.2 AFW Valves

Auxiliary feedwater valves 1-AFW-101, 102, 115, 116, and 117 are located in the same pump room (EL. 12' of Turbine Building) as the turbine-driven AFW pumps. Visual inspection indicated no external damage, cleanliness problems or indications of major water leaks. Sources of combustion, fire protection/-prevention systems, environmental conditions, and potential system interactions were as described for the turbine-driven AFW pumps.

Auxiliary feedwater valves 1-AFW-191, 1-CV4520, 1-CV 4521, 1-AFW-193, 1-AFW-162, 1-CV4511, 1-AFW-192, 1-CV4530, 1-CV4531, 1-AFW-194, 1-AFW-164, 1-CV4512 1-AFW-130, 1-MS-103, 1-MS-106, 1-CV4070, 1-CV4071, 1-MS-102, 1-MS-222, and 1-MS-105 are located in a valve/piping room at elevation 27' of the Auxiliary Building. Visual inspection indicated no external damage or cleanliness problems or indications of major water leaks. No combustion sources were observed in the area since this is essentially a room for housing valves. No potential interactions with non-Q systems were noted.

Auxiliary feedwater steam valves 1-MS-109 and 110 are located in the same pump room (EL. 12 of the turbine building) as the turbine driven AFW pumps. Visual inspection of the valves indicated the same results.

6.3.3 Motor-Driven AFW Pump No. 13

Visual observations of AFW Pump No. 13 indicated that:

-- During routine maintenance work near by the pump, dust covers and temporary filters were provided to the AFW pump motor to prevent dust getting into the motor casing.

-- Ground wire for the pump motor was free from corrosion and secured properly.

-- Identification label for the AFW pump No. 13 was not posted. This is an example of an unresolved item detailed in Section 9.1.3.

6.4 Preventive Maintenance

Preventive maintenance review consisted of an examination of preventive maintenance schedules and records for the past two years, a review of preventive maintenance procedures and interviews with preventive maintenance personnel and an actual "talk through" of selected preventive maintenance procedures. The licensee is committed in the Administrative Section of the Technical Specifications to Regulatory Guide 1.33 and thus to ANSI N18.7 (1976). "Preventive Maintenance Program," CCI-211D was reviewed to verify that:

- Preventive procedures existed for the selected components
- The licensee was performing per procedural requirements for the selected components
- Technical Specification Requirements of Limiting Conditions for Operation were properly documented.
- The preventive maintenance and/or frequency were adequate
- The preventive maintenance procedures were clear and technically adequate, and components were properly returned to service
- The maintenance personnel were knowledgeable.

These objectives are discussed below for each component, as appropriate.

6.4.1 Turbine-Driven AFW Pumps No. 11 and 12

The following preventive maintenance procedures exist for the turbine-driven AFW pumps:

Component	Procedure No.	Brief Description
AFW Pump Turbine No. 11	1-36-M-A-1	Lubrication (governor & overspeed)
AFW Pump Turbine No. 12	1-36-M-R-6	Align & Lubricate coupling

AFW Pump Turbine No. 11	1-36-M-R-5	Align & Lubricate coupling
AFW Pump Turbine No. 12	1-36-M-A-2	Lubrication (governor overspeed)&
No. 12 AFW Pump	1-36-M-5A-2	Torque Holddown Bolts
No. 11 AFW Pump	1-36-M-5A-2	Torque Holddown Bolts
No. 12 AFW Pump	1-36-M-2M-2	Vibration Readings
No. 11 AFW Pump	1-36-M-2M-1	Vibration Readings
No. 12 AFW Pump	1-36-M-M-2	Pump & Turbine Bearing Oil Change
No. 11 AFW Pump	1-36-M-M-1	Pump & Turbine Oil Change

A review of these procedures indicated that they were reasonably clear and technically adequate. The types of preventive maintenance and frequency were satisfactory. Discussions with maintenance personnel and a "talk through" of several procedures indicated that the personnel training was adequate and maintenance personnel had a thorough knowledge of procedural requirements.

A review of preventive maintenance records over the last two years indicated that preventive maintenance was being performed as required. Preventive Maintenance records reviewed are provided in Attachment.

6.4.2 AFW Valves

No preventive maintenance procedures exist for any of the selected auxiliary feedwater valves. As discussed in Surveillance Testing, testing is performed on a periodic basis. In addition, a review of corrective maintenance records did not reveal any unusual maintenance problems.

6.4.3 AFW Pump Steam Valves

The control valve, 1-CV-4070, which supplies main steam to AFW Pump turbine No. 11 had preventive maintenance performed in accordance with 1-83-M-R-3. This included replacing the operator diaphragm. Preventive maintenance was not performed on any of the other selected auxiliary feedwater steam valves.

A review of the above procedure and maintenance records did not uncover any problems. Valves not covered under a preventive maintenance procedure were tested on a periodic basis (see Surveillance Section). In addition, a review of corrective maintenance records did not reveal any unusual problems. The overall preventive maintenance program was thus determined to be satisfactory in this area.

6.5 Corrective Maintenance

The corrective maintenance review consisted of an examination of corrective maintenance records for the past two years, a review of corrective maintenance procedures, and interviews with selected maintenance personnel. The inspection objectives were to verify that the requirements specified in the Administrative Section of the Technical Specifications and CCI 200I, "Nuclear Maintenance System", were met, and that:

- Corrective maintenance had been performed on the selected components
- The maintenance was performed per procedural requirements
- Technical Specification Requirements of Limiting Conditions for Operation and Surveillance were properly documented operation
- The maintenance procedures are clear and technically adequate and components are properly returned to service
- The corrective maintenance is adequate as evidence by the number of repetitive failures

The maintenance records reviewed are tabulated in Attachment.

6.5.1 Turbine-Driven AFW Pumps No. 11 and 12

For the past two years, the licensee had a manual system for tracking and retaining maintenance requests. Some difficulty was encountered in obtaining these records during the inspection and ascertaining whether the records were complete. The licensee has recently implemented a computerized maintenance tracking system which hopefully will allow better retrieval.

A review of the maintenance records indicated that corrective maintenance had been performed per procedural requirements and that Technical Specification Requirements of Limiting Conditions for Operation had been considered. A technical review of the procedures indicated that the procedures were technically adequate and that the corrective action had been effective.

6.5.2 AFW Valves

The following maintenance requests were reviewed for the auxiliary feedwater valves:

MR No.	Component	General Description
0-84-4101	1-CV4070	Ruptured diaphragm
P-84-7736Aa	1-CV4070	Valve closing time in Alert Range
0-84-0013	1-CV4071	Steam leak
P-84-8137	1-AFW-4512	Excessive Stroke Time

The review of the above MR's indicated that the maintenance had been performed in accordance with procedural requirements and that Technical Specification requirements of Limiting Conditions for Operation had been considered. A technical review of the procedures indicated that the procedure was technically adequate and that the corrective action had been effective.

6.6 Surveillance

Surveillance inspection consisted of witnessing actual surveillance testing, a review of test procedures, discussions with operators and a review of test results.

Surveillance test procedures are divided into three areas: operations, E&IC, and Maintenance. The two procedures primarily concerned with the auxiliary feedwater system are 0-5-1 Auxiliary Feedwater System Test and 0-9-1 AFAS Monthly Logic Test, both of which are performed by operations.

The objectives of the surveillance test review were the following:

- To verify that surveillance testing had been performed on the selected components, and, if Technical Specification Requirements were involved, that these requirements had been met;
- To verify that the surveillance testing was performed per procedural requirements;
- To determine if the surveillance test procedures were clear and technically adequate;
- To verify that the testing met its intended objectives and that components were properly returned to service after completion of the test;
- To verify that the test results were within the required range and that appropriate action was taken and
- To evaluate the performance and knowledge of operator (test) personnel

6.6.1 Turbine-driven AFW Pumps No. 11 and 12

On March 11, 1985 the licensee performed surveillance test, 0-5-2, Auxiliary Feedwater System Test on Unit 2. This is a monthly surveillance which tests the operation of the overall auxiliary feedwater system and is required by Technical Specification 4.7.2. As such, it tests the following components.

- Turbine-driven AFW pump No. 21
- Turbine-driven AFW pump No. 22
- Motor-driven AFW pump No. 23
- Valves 1-MS-4070, 1-MS-4071
- Flow control valves CV-4511 and CV-4512 (timing tests)
- Flow control valves CV-4525 and CV-4535
- Cross Connect valve CV-4550 (timing test)

The test witnessed by the inspector indicated that the operators were knowledgeable of test procedures, that test results were within the required range and that all components were properly returned to service. Values recorded during this test were:

Component	Variable	Value	Alert/Action Value
1-MS-4070	Opening time (sec)	64.21	80.4/110
1-MS-4071	Opening time (sec)	64.43	81.3/80
No. 21 Pump	TDH (ft)	2914.11	2800 minimum
No. 22 Pump	THD (ft)	2845.97	2800 minimum
No. 21 Pump & Local Vibration Turbine	(mils)	.11-.2	0-1
No. 22 Pump & Local Vibration Turbine	(mils)	.13-.25	0-1
No. 23 Pump	TDH (ft)	3226.4	3100
No. 23 Pump Local Vibration (mils)		.09	0-1
CV-4511	Opening Time	30.25	30.4/90
CV-4512	Opening Time	30.42	34.9/90
CV-4525	Opening Time	10.58	13.3/90
CV-4535	Opening Time	17.88	20.8/90
CV-4550	Opening Time	40.23	45.8/90

Although these results were for Unit 2 similar results were expected for Unit 1 since the Unit 1 and 2 components were identical. In order to verify this, the inspector reviewed test results for the last two 0-5-1 tests performed on Unit 1. These test results, performed on 1-25-85 and 2-25-85,

indicated that all values except for the opening times on valves CV-4511 and CV-45-12 were below the Alert/Action values. The opening times for these valves were above the alert values but below the action limit. MR's 0-84-2677 and P-85-8851 had been initiated by the licensee to correct this situation.

Alert values are administrative limits which indicate that a component's performance relative to initial performance has degraded. When alert values are exceeded, the licensee increases the surveillance testing frequency of the component. Action limits are values which may be related to Technical Specification requirements. Exceeding an action limit, therefore, may force the licensee into the appropriate Action Statement associated with that TS.

During the performance of the 0-5-2 test on Unit 2 the inspector notice the high temperature experienced in the auxiliary feedpump room. This led to several questions regarding the relationship of the design capability of the HVAC equipment and some of the electronic equipment in the room. This is discussed in "Findings".

The test procedure and test results for 0-9-1, "AFAS Monthly Logic Test" were reviewed. This is a monthly surveillance test of the auxiliary feedwater actuation system logic and is required by Technical Specification 4.7.1.2.

A review of the test procedure and test results indicated that the surveillance testing was performed in accordance with procedural requirements, that the procedures were clear and technically sufficient, and that the test results were within the acceptable limits.

6.6.2 AFWP Valves

Several auxiliary feedwater valves were tested in the surveillance procedures 0-5-1 and 0-9-1. As discussed for the turbine-driven auxiliary feedpumps. These procedures and test results from previous two tests did not indicate any problems except for the opening time problems discussed for CV-4511 and CV-4512.

6.7 AFW Pump Room Ventilation

The normal ventilation system in the turbine-driven AFW Pump room is designed to maintain the room temperature at 130°F. The emergency ventilation system, consisting of two emergency circulation fans, is marginally capable of maintaining the room temperature within the specification. Instructions are provided to shut off the room lighting to reduce the room heat load. In addition, the doors leading to the

main turbine bay area must be opened during pump operations. This is to aid in the cooling of the inboard and outboard pumping journal bearings of the AFW pumps by the room air via convective heat transfer. A local temperature indicator is the only indication available to monitor the room temperature. However, during pump testing, this is not required to be monitored.

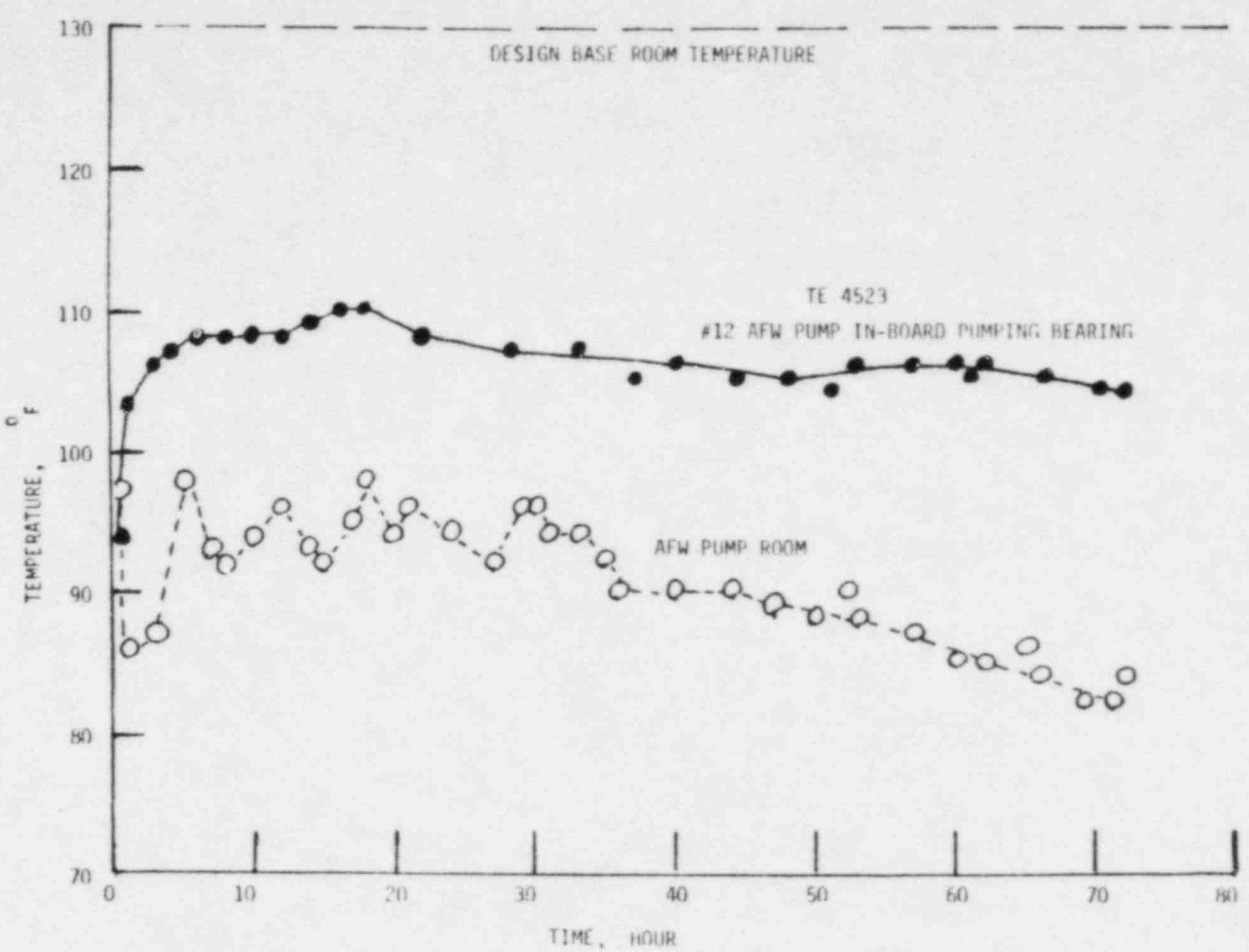
During Unit 2 AFWS surveillance testing per STP 05 on March 11, 1985, the inspector noted that the pump room temperature rapidly increased when steam was introduced into the AFW Pump turbine, even though the room temperature remained below 120°F.

The licensee conducted a special 72 hour AFW Pump test (TSP-30) on January 8, 1980 to demonstrate room cooling, and to ensure that the equipment within the room would be compatible with the environmental conditions during the pump operations. The inspector plotted the test data as shown in the Figure 6.7 to understand the cooling characteristics.

In this test, the two doors leading to the main turbine bay were opened 15 minutes into the test. When the doors were opened, the room temperature quickly decreased by more than 12°F as shown in Figure 6.7 and oscillated for more than 20 hours until convective heat removal and air circulation stabilized. The bearing temperatures remained well within the operating limits. The following table summarizes the maximum inboard and outboard bearing temperatures observed during the test.

Bearings	Maximum	Temperature °F Control Room Alarm
Turbine Journal (Oil-cooled)		
TE4047	188	195
TE4048	161	195
Pumping Journal (Air Cooled)		
TE4522	97	180
TE4523	110	180

The bearing temperatures were monitored from the process computer CRT display in the control room. Based on these test results, it was concluded that the bearing temperatures remained within acceptable limits. However, the air circulation provided by opening the doors to the main turbine bay should be incorporated into the station emergency procedures. This was an example of the open item discussed in Section 6.9.



AFW PUMP BEARING AND ROOM TEMPERATURES

Figure 6.7

Another concern was the environmental qualification (EQ) of instruments in the pump room for the increased ambient temperatures encountered during testing or during pump operations. A licensee internal memorandum dated August 13, 1984 by an EQ senior engineer identified a significant reduction of instrument life for a pump room temperature of 120°F. The instruments concerned included Rosemount pressure transmitters and damper operators in the AFW pump rooms.

6.8 AFWS Flow Instability

The original auxiliary feedwater system at Calvert Cliffs contained two turbine-driven auxiliary feed pumps. During the 1982 Unit 2 refueling outage (and previously on Unit 1), a third motordriven pump was added. During testing of the pump, it was observed that a system flow instability problem exists when starting the motor-driven auxiliary feed pump at low steam generator pressures. This was attributed to cycling of the automatic recirculation (ARC) valve and a flow control valve with a high flow capacity (Cv).

This problem was partially corrected on Unit 2 by changing the trim on the flow control valve and disabling the ARC. In addition the flow control valve is required by procedure to be operated manually. For Unit 1, the flow control valve is also required to be operated manually. However, the trim has not been installed and the ARC valve has not been disabled.

The licensee intends to further change the control valve trim and replace the ARC valve with a check valve on both units. The licensee plans to eventually return to automatic operation. The necessary modifications will be made at the next unit outage.

6.9 Findings

No violations of license conditions or other deficiencies were identified.

No external damage, indications of major steam/water or oil leaks or cleanliness problems were observed during the visual inspections. Bearing oil levels for the pumps were satisfactory; combustion sources were minimal; and ceiling smoke detectors and a water spray system were provided. No problems were identified in the system interactions between non-"Q" and "Q" systems. Also, major equipment was easily accessible and local indications were available.

Some of the AFW valves did not have preventive maintenance procedures. However, surveillance records and corrective maintenance records for these valves indicated no major valve problems existed. Preventive maintenance was performed on pumps and major valves. Personnel conducting the maintenance work had a thorough knowledge of procedural

requirements and adequate training. Some difficulty was experienced in retrieving the maintenance records; however, a computerized maintenance tracking system was implemented recently which should correct this problem.

During surveillance testing, it was observed that some AFW steam and flow control valves did not meet the acceptance criteria for their opening times. The licensee promptly initiated maintenance requests to correct the problems. The test was conducted in accordance with the procedure and the personnel demonstrated a satisfactory knowledge of the test.

A recommendation was made to review the effects of pump room temperature on the instruments during pump operations or tests. In addition, it was recommended that the room temperature should be monitored during pump operations and tests. The licensee stated that this would be reviewed and the above findings would be incorporated into the appropriate test and emergency operating procedures if appropriate. This is an unresolved item (317/85-03-03).

The inspector discussed AFW MD pump test results and system operation with licensee personnel. In addition, the inspector reviewed the test results of TSP #165, Rev. 0, dated April 21, 1984, "AFW Motor-Driven Pump Test" and a letter, dated May 24, 1984, which included data from several tests. This is an unresolved item for Unit 1, pending the license's corrective action and subsequent NRC:RI inspection (317/85-03-04).

Based on the above, it was concluded that the AFW would be available for operation.

7.0 Salt Water and Component Cooling Water Systems

The salt water system (SWS) is a two train system. It provides secondary cooling for the SRWS and CCWS and cooling for the ECCS pump room and circulating water pump seals. The component cooling water system (CCWS) is a closed cooling system which provides cooling to various safety and non-safety components. Both of these systems provide important functions and thus were inspected.

7.1 Salt Water System (SWS)

7.1.1 Procedures

The inspector reviewed procedures to assure adequate instructions were available to the station staff for control and lineup of the following SWS components.

-- SW 5170, ECCS Pump Room Cooler No. 11 SW Inlet Valve
-- SW 5171, ECCS Pump Room Cooler No. 11 SW Outlet Valve

-- SW 5162, Component Cooling Water (CCW) Heat Exchanger (Hx) No. 12 Inlet
-- SW 5163, CCW-Hx No. 12 Outlet
-- SW 5160, CCW-Hx No. 11 Inlet
-- SW 5206, CCW-Hx No. 11 Outlet

SW-5170/5171 are normally closed valves which open on high temperature in the ECCS pump room. Procedure OI-29, "Salt-water System - Unit 1", valve lineup check off places these valves in the closed position. Section XIII of OI-29 requires a monthly flow verification of the ECCS air coolers to assure that SW flow is available to the ECCS pump room coolers. This procedure requires manual opening and closing of SW 5170 and 5171 using the hand switch in the Control Room.

OI-29 valve lineup opens SW-5162, 5163, 5160 and 5206. Also, the procedure requires operation of the heat exchanger and ECCS cooler inlet and outlet valves from the Control Room to establish or re-establish SW System Operation.

EOP-5, "Loss of Reactor Coolant," contains checklists for the Safety Injection Actuation Systems (SIAS) and the Containment Sump Recirculation Actuation Systems (RAS) to ensure that proper automatic actuations have taken place on SIAS and RAS signals. The SIAS checklist verifies that the SW inlet and outlet valves to the CCW-HX have closed on an SIAS signal to divert SW to the Service Water System Heat Exchangers. The RAS checklist verifies that these valves have opened on an RAS signal. ECCS Pump Room SW valves are not on these checklists as they are temperature activated and do not activate on an RAS or SIAS signal.

In EOP-5, the first supplementary action following the Loss of Coolant Accident (LOCA) immediate action steps is to start both ECCS Pump Room Air Cooler Fans. However, EOP-5 does not require checking that the SW inlet and outlet valves to the fan coolers have opened or that they be opened manually.

A high temperature in the Auxiliary Building will cause an alarm in the Control Room. The specific area which gave the alarm in the Control Room must be verified in the Switchgear Room. If the alarm is determined to be in the ECCS Pump Room, the alarm response procedure requires verification of proper operation of the ECCS Pump Room Coolers but does not specify operation of specific valves.

7.1.2 Operational Features

Valves SW-5170, 5171, 5162, 5163, 5160 and 5206 are pneumatically operated valves. They are operated from the Control Room using hand switches, and each valve has a position indication in the Control Room. The valves are located in the

Component Cooling Water Heat Exchanger Rooms, are easily accessible, and are clearly identified.

SW-5162, 5163, 5160 and 5206 can be opened locally by failing the air operators on the valve; however, there are no manual operators on the valves. Valves SW-5170 and 5171 can also be opened locally by failing the air operators. In addition, these valves have manual wheel operators. It should be noted that SW-5170 and 5171 are not located in the ECCS Pump Room although they are inlet and outlet valves to the pump room fan coolers. This enhances operations as the ECCS Pump Room would become inaccessible during an RAS.

7.1.3 Operational Simulation

One operator verified the location of each of the previously discussed valves; each valve was properly identified. Manual operation for each valve was simulated by the operator.

7.1.4 Training

Plant operators receive extensive training on the operation of the Salt Water System. Lesson plans specifically discuss the operation of the CCW-Hx SW inlet and outlet valves and ECCS pump room coolers, including system walkdowns of major components and participation in operational tests.

7.1.5 Findings

No violations of licensee requirements or deficiencies were observed.

Based on procedural controls, operator knowledge and training, and ease with which the valves can be operated, it was determined that the probability of an operator failing to open these salt water valves when needed would be minimal.

7.2 Component Cooling Water (CCW) System

7.2.1 Procedures

Valve 1-CC-3826, normally closed, is the outlet valve for Component Cooling Water Heat Exchanger (CCW-HX) No. 12. Procedure OI-16, "Component Cooling System - Unit 1", is the overall operating procedure for the CCW System. The valve lineup checklist in OI-16 requires 1-CC-3826 be closed for normal operation. If the CCW heat exchangers are to be shifted or if CCW-HX No. 12 is to be placed in service, OI-16 specifically states that 1-CC-3826 is to be opened.

A recent interim change has been made to EOP-5, "Loss of Reactor Coolant." A supplementary operator action step has been added to check both CCW-HX outlet valves 1-CC-3824 and 1-CC-3826 for the open position after initiation of the RAS. AOP-7C, "Loss of Component Cooling", provides a recovery procedure for loss of CCW flow. This procedure states a number of things to look for to recover CCW flow including checking the valve lineup. However, neither 1-CC-3826 nor any other CCW valve is specifically addressed by this procedure.

If there is a high temperature alarm for CCW-HX No. 11, the alarm response procedure delineates several causes mainly for loss or degradation of salt water cooling. The next action is to place the No. 12 CCW-HX in service.

7.2.2 Operational Features

1-CC-3826 is a pneumatically operated valve which is normally operated from the Control Room. There is valve position indication for the valve on its control panel. Although it is a normally shut valve, it will fail open on loss of air. 1-CC-3826 is located in the Component Cooling Water Heat Exchanger Room in the Auxiliary Building; is accessible and is clearly marked. There is no manual operator on the valve; however, it can be opened manually by locally failing the air operator.

7.2.3 Operational Simulation

Local operation of 1-CC-3826 was simulated by removing air locally. A CCW high temperature was simulated in the Control Room for a Unit 1 and a Unit 2 Control Room operator. Operators simulated several actions mainly to check for adequate salt water flow to the No. 11 CCW-HX. Operators were aware of the need to place the CCW-HX in service and to open 1-CC-3826. There was no immediate response to correct the alarm condition but this is consistent with actions in abnormal operating and alarm response procedures.

7.2.4 Training

Discussions with instructors, review of CCW system lesson plans, and review of CCW system operator qualification sheets indicate that extensive training is given on the operation of CCW system and the CCW heat exchangers. One lesson plan provides training on the shifting of CCW heat exchangers and the need to assure that the heat exchanger outlet valve has been opened. Training includes system walkdowns and a practical operations test. Sufficient training is given to indicate that plant operators are knowledgeable in the operation of 1-CC-3826.

7.2.5 Findings

No violations of licensee requirements or other deficiencies were observed. Valve 1-CC-3826 was readily operated from the Control Room or locally. Procedures and operator training assured that this valve would be opened should a second CCW heat exchanger need to be put in operation.

For CCW high temperature alarms, operators were trained to look for salt water deficiencies first. The need to put a second CCW cooler in service (and open 1-CC-3826) would be a secondary action. Based on the above, it was determined that the probability of an operator error which would fail to open 1-CC-3826 when needed whould be minimal.

7.3 Availability of Mechanical Components

7.3.1 Scope

The review of mechanical components in the salt water and component cooling water systems primarily focused on the components identified in the IREP study. These included:

-- Valves

- CC-0258
- SWS-5206 and SWS-5208
- SWS-5160
- CC-3823, CC-3825 and CC-3826
- SWS-5170, SWS-5171
- SWS-5162, SWS-5163
- Pump
- Salt Water Pump No. 13
- Heat Exchanger
- Component Cooling Water Heat Exchanger No. 12

Each component was reviewed to establish that it would not cause loss of system function and that, if challenged, would function. In order to accomplish this goal, several activities related to each component were performed. These activities included:

-- Visual Inspection (including fire protection and ventilation)
-- Preventive Maintenance Review
-- Corrective Maintenance Review
-- Witnessing of Surveillance Testing and Review of Results
-- Review of Procedures Related to the Above

7.3.2 Visual Inspection

Visual inspection consisted of an examination of the component and the area around the component. Support systems, such as HVAC and fire protection/prevention systems were also examined. Visual inspection included the considerations discussed in the inspection methodology.

Component cooling water heat exchanger No. 12 and valves CC-3825 and CC-3823 are located in a cubicle at Elevation -10' of the Auxiliary Building. Visual inspection of the heat exchanger indicated that the corrective maintenance had been performed on the channel side (salt water side). This corrective action is consistent with an overall improvement effort by the licensee for the Salt Water System and is further discussed in the Maintenance Section. Combustion sources in these areas are very limited.

Salt water pump No. 13 is located by the circulating water pumps at the Intake Structure. Salt water system valves SWS-5170, SWS-5171, SWS-5162, SWS-5163, SWS-5160 and SWS-5206 are located at Elevation 5' of the Auxiliary. Visual inspection of the equipment indicated no external damage, cleanliness problems, or indications of water leaks. Combustion sources in these areas are very limited.

7.3.3 Preventive Maintenance

The preventive maintenance review consisted of an examination of preventive maintenance schedules and records for the past two years, a review of preventive maintenance procedures, and interviews with personnel.

Because of corrosion problems in the Salt Water System, the licensee has adopted an aggressive preventive maintenance program for this system. This program includes cathodic protection, wall thickness measurement, and the following preventive maintenance procedures:

Component No.	Procedure No.	Brief Description
SWS-0111	1-12-M-W-1	Lubricated Hinge Pins
Salt Water Pump No. 13	1-12-M-M-3	Lubricated Pump Bearings
Salt Water Pump No. 13	1-12-M-2M-3	Vibration Readings
Salt Water Pump No. 13	1-12-M-SA-3	Oil Samples
Salt Water Pump No. 13	1-12-M-A-11	Coupling Inspection

SWS-5163, 5206 & 5208	1-12-M-A-14	Lubricate Valves
Salt Water Pump No. 13 Expansion Joints	1-12-M-A-16	Inspect Expansion Joint
Salt Water Pump No.13	1-12-M-6YR-1	Disassembly Pump and Clean Parts
Component Cooling Water Heat Exchanger No. 12	1-15-M-Q-4	Tube Cleaning and Cathodic Protection
Component Heat Exchanger No. 12	1-15-M-R-2	Eddy Current Testing

In addition to these preventive maintenance procedures, several of the components are included in the licensee's surveillance program and/or locked valve controls list. A review of these procedures indicated that they were reasonably clear and technically adequate. Discussions with maintenance personnel indicated a thorough knowledge of procedural requirements.

7.3.4 Corrective Maintenance

A corrective maintenance review was conducted consisting of an examination of records for the past two years, a review of procedures, and interviews with selected maintenance personnel.

The licensee is committed in the Administrative Section of the Technical Specifications to Regulatory Guide 1.33 and thus to ANSI 18.7 (1976). Section 5.2.7 describes maintenance, and CCI 2001, "Nuclear Maintenance System", describes the overall maintenance program and the initiation of maintenance requests.

A review of selected maintenance records indicated that corrective maintenance had been performed. Much of this maintenance was related to corrosion problems in the Salt Water System. The No. 12 component cooling water heat exchanger channel which was previously repaired and is cast iron, is being replaced with a carbon steel head as part of corrective maintenance.

The review of maintenance records indicated that corrective maintenance had been performed per procedural requirements and that Technical Specification requirements of Limiting Conditions for Operation had been considered. Corrective maintenance records reviewed are provided in the Attachment. A review of the procedures indicated that they were technically adequate.

7.3.5 Surveillance

Inspection of the licensee's surveillance program consisted of witnessing actual surveillance testing, a review of test procedures, discussions with operators, and a review of the test results for several test occurrences.

Surveillance test procedures are divided into three areas: operations, E&IC, and maintenance. The two procedures primarily concerned with the system are;

-- 0-65-1 Quarterly Valve Operability Verification
-- 0-73-1 Equipment Performance Test

On March 12, 1985, the inspector witnessed the performance of STP-0-65-1 for valve SWS-5206. This valve was being tested for opening time since it had previously failed to open within the Alert time. When this occurs, the licensee increases the surveillance testing frequency. Witnessing of the test by the inspector verified that the operators were knowledgeable of test procedures; that the test was performed per procedure; that test results were not in the Action (out of Technical Specification) range; and that all components were properly returned to service. An opening time of 67.8 seconds was recorded compared to an alert value of 40.1 sec. The procedure did not require any corrective measures. However, this requires the test frequency to be increased which the licensee subsequently implemented.

The inspector also reviewed test results for several previous tests. These test results also indicated that valve SWS-5206 had an opening time in the Alert range and that the other valves tested, i.e. SWS-5160, SWS-5170, SWS-5171, SWS-5208, SWS-5163, SWS-5162 and CC-3826 had performed satisfactorily.

On March 13, 1985, the inspector witnessed performance of STP-0-73-1 for Salt Water Pump No. 13. This surveillance measures vibration and discharge pressure of the pump. Witnessing of the test by the inspector indicated that the tests were performed per procedure, that test results were within the required range, and that all components were properly returned to service.

7.3.6 Findings

No violations or deviations were identified.

The licensee valve surveillance test is conservative in that surveillance is increased when alert levels are exceeded. Conformance with the procedural requirements was demonstrated several times.

Because of the corrosion problems in the Salt Water System, an aggressive preventive maintenance program was instituted for the system. Also, the maintenance and surveillance programs in this system focused on preventive measures.

Within the scope of this inspection, it was determined that the Salt Water System and components would be available if called upon to function. However, a long term resolution of the salt water corrosion problems is desirable.

7.4 Availability of Electrical Components and Control

7.4.1 Scope

The following components were inspected in the salt water system (SWS).

- Salt Water Pump No. 13
- Motor
- Motor Electrical Supply Breaker, cables and controls
- Component Cooling Water Heat Exchanger No. 11
- Salt Water Inlet Valve, SWS CV 5160
- Electrical Control
- Salt Water Outlet Valve SWS-CV-5206
- Solenoid Valve 1-SV-5206, 1 SV 5160 and 1-SV-5260A

7.4.2 Visual Inspection

The electrical breakers and disconnect switches which control the power supply to the SWS pumps were identified with name plates. Also, the switchgear areas Bus No. 11 and No. 14 did not have any electrical hazards present nor any combustible material in the areas. There were fire detectors in the areas, the areas were protected from fire by an area halon flooding system, and access control was by key card readers.

The salt water pump no. 13 motor was located in the circulating water pump area, and the door into the area from the turbine building was water tight. A sign was posted on the door with an instruction that the door must be closed.

The pump area air was humid but no electrical hazards were present in the area. Also, the only combustible material in the area was lubricants. The pump motor power cables were routed in conduit, and a large sign located above the motor identified the pump.

The CCW HX No. 11 area contained no electrical hazards. The combustion material in the area was electrical insulation and lubricants.

7.4.3 Document Reviews

Preventive Maintenance (PM)

Evaluation of the following reviews are discussed in the findings section:

-- PM 1-12-E-2YR-1: Salt Water Pump Nos. 11, 12 & 13 Feeder Breakers 152-1105, 152-1405, 152-1412, 152-1112, Test conducted 1-30-82
-- PM 1-12-E-2R-1 Salt Water Pump 11, 12 and 13 motors, Revision 1, Test Conducted date 9-28-83

Corrective Maintenance - Maintenance Requests (MR)

Maintenance records reviewed are listed in the Attachment.

Drawings

-- 1E-80, SH-8 Rev 7, Schematic Diagram Salt Water Pump 13 AC 3 Line
-- 1E-80, SH 9A, Rev 0, Schematic Diagram Salt Water Pump 13 Switch Development
-- 1E-80, SH 10, Rev 9, Schematic Diagram Salt Water Pump 13 BKR 152-1112
-- 1E-80, SH 9, Rev 12, Schematic Diagram Salt Water Pump 13 BKR 152-1413
-- 1E-76, SH 36, Rev 5, Schematic Diagram Reactors Safeguards Salt Water HX 11 Valves 1-CV-5160 and 1-CV-5206

Nuclear Power Experience

-- Volume PWR-2, Book 4, Experiences, Chapter XI Electrical Systems

    a. Emergency Power Pages 1 through 192
    b. Other Electrical Pages 1 through 210

7.4.4 Findings

There was no failure history of the safety related components: 4000 Volt motors; 480 Volt motors; 4000 Volt Cables; 480 Volt Cables; Control Cables; and 480 Load Center Breakers. Also, no previous failures were identified for the following hardware:

-- SW Pump No. 13 Control Switches 1-HS-5201 and 1-HS-5201B
-- SW Pump No. 13 Breaker Control Auto Closing Timer
-- Control Switch 1-HS-5161
-- Auxiliary Relay Rowan Controller
-- Solenoid Valvues 1-SV-5160, 5206 and 5206A

The failure records associated with the 4000 volt breakers (GE type AMH-4.76-250-1D) indicated that over sized trip rollers were replaced by GE, and that auxiliary switch failures were found during preventive maintenance. Also, charging motor problems were identified. All safety related 4000 Volt breakers and all non-safety 4000 volt breaker will be sent off to the vendor for reconditioning.

There were no violations or deviations of regulatory requirements, associated with the systems or components reviewed. The evaluation of corrective maintenance indicated that failures were detected and corrected during surveillance test and preventive maintenance programs.

8.0 rimary and Secondary Heat Removal Systems

8.1 Primary Heat Removal Systems

8.1.1 Assessment of Feed-and-Bleed Operations

8.1.1.1 Procedures

During or subsequent to an accident, the primary system is the main source of cooling for the reactor core, and cooling water can be injected into the core while simultaneously removing water from the core - a "bleed and feed" operation. Calvert Cliffs has developed a procedure for primary bleed and feed - AOP-3C, "Small break Loss of Coolant Accident Long Term Cooling", Section II, "Long Term Cooling Via RCS Blowdown to Containment".

In order to remove water from the core, AOP-3C creates a deliberate loss-of-coolant situation by opening the power operated relief valves (PORV's) and assuring that the PORV blocking valves are also open. Water is added to the core by continuing high pressure injection. Any one of the following procedures could be used for adding water to the core:

-- OI-3, "Safety Injection, Shutdown Cooling, and Containment Spray Unit 1"
-- OI-2A, "CVCS Volume Control Unit 1"
-- AOP-3A, "ECCS Long Term Cooling Core Flush"
-- AOP-1C, "Emergency Boration"
-- EOP-5, "Loss of Reactor Coolant"

8.1.1.2 Operational Features

Both PORVs and the PORV blocking valves 1-RC-403 MOV and 1-RC-405 MOV can be opened from the Control Room. The PORVs can be opened by removing two Reactor Protection System High Pressure Trip units which transmits a 2 of 4 high pressure signal to the PORVs causing them to open. Opening of the PORVs can be verified by any of the following indications in the Control Room.

-- Sonic detector plus alarm
-- PORV energized alarm
-- Downstream temperature alarm
-- Increases in quench tank level, temperature and pressures

In order for the PORVs to function, their blocking valves must be open. These valves are normally key-locked open via handswitches in the Control Room and there is valve position indication available on the panel.

Both the PORVs and their blocking valves can be operated locally in the containment. This could not be physically verified during this inspection as both Units 1 and 2 were operating. However, it is unlikely that local operation would be feasible because conditions in the containment during an accident situation would make containment entry impossible.

As noted above numerous methods are available for adding water to the reactor in a feed and bleed situation using the high pressure injection and/or the charging system. The normal method would be high pressure injection. All methods of charging are readily available from the Control Panels with various levels of redundancy.

8.1.1.3 Operational Simulation

Two Control Room operators demonstrated knowledge of "feed and bleed" operations by simulating the opening of the PORVs and their blocking valves. The operators discussed operation of PORV controls, the need to pull RPS cards, and the blocking valve hand switches. One operator simulated the various modes by which water could be added to the plant by Control Room panel operators.

8.1.1.4 Training

Lesson plans were available which discussed all modes of operation for safety injection of water into the plant. There is a specific lesson plan for loss of shut down cooling. This lesson specifically discusses the use of the PORVs as a bleed path if shut down cooling is unavailable.

8.1.2 Assessment of Operations - High Pressure Safety Injection Recirculation Mode

There are three motor-driven HPSI pumps, each with a capacity of 345 gpm. On a Safety Injection System Actuation Signal (SIAS) all three pumps discharge to two discharge headers which in turn discharge to four primary loops. The HPSI pumps take suction from the Refueling Water Tank (RWT) which contains a minimum of 400,000 gallons of water.

If the RWT reaches a minimum level there will be a Recirculation Actuation Signal (RAS). This will cause the suction of all three HPSI pumps to be isolated from the RWT. On the RAS two containment sump suction valves open and provide containment sump water as a supply to one of the three HPSI pumps. The other two HPSI pumps remain isolated. Primary water now recirculates from the primary system to the HPSI pump.

8.1.2.1 Procedures

During High Pressure Safety Injection (HPSI), if a recirculation actuation signal (RAS) is received, Containment Sump valves 1-SI-4144-MOV and 1-SI-4145-MOV open automatically to allow the HPSI pumps to take suction from the Containment Sump. If these valves do not open automatically they must be opened manually.

EOP-5, "Loss of Reactor Coolant", RAS Check-Off List provides verification that valves 1-SI-4144-MOV and 1-SI-4145-MOV have opened on a RAS signal. If the valves have not opened, they can be opened manually. Procedure OI-3, "Safety Injection...Unit 1" initial

valve lineup provides the 1-SI-4144 and 1-SI-4145 be shut for normal operation. There are no procedures for opening the valves as they would only be opened following a RAS.

8.1.2.2 Operational Features

If 1-SI-4144-MOV and 1-SI-4145-MOV do not open automatically on a RAS, they can be opened manually by the use of handswitches in the Control Room. Each valve has a separate power supply and fails "as-is" on loss of control power. There is valve position indication in the Control Room to verify the position of each valve.

The RAS can be manually initiated from the Control Room which will also cause 1-SS-4144 and 1-SI-4145 to open. Operators will normally initiate an RAS signal manually rather than wait for an automatic actuation signal.

The manual operators for each valve are located in the Auxiliary Building precluding the need for a containment entry in case of the need for local manual operation. The valves operators are located side by side, are easily accessible, and are clearly identified. If local manual operation were required to open the valves, it could readily be performed.

8.1.2.3 Operational Simulation

Using one Control Room operator, manual actuation of the valves from the Control Room was discussed and simulated. This included actuation of the RAS and operation of the valve handswitches. The valve operators were also located in the Auxiliary Building. Manual operations were simulated.

8.1.2.4 Training

Extensive training is given to control room operators and auxiliary building operators. The Auxiliary Building training study guide and record provides specific checkouts in the Safety Injection System, procedure EOP-5, engineered safety features test, and system walkdown and checkouts. Safety injection lesson plans specifically cover RAS actuation and the need to open 1-SI-4144 and 1-SI-4145.

8.1.3 Surveillance Test of Primary Pressure Relief Valves PORV

Two PORVs are designed to relieve the primary system pressure with a discharge capacity of 153,000 lb/hr at 2400 psig for each PORV. The RPS trip setpoints and transmitter calibrations, performed November 9, 1983 and November 2, 1983 respectively, under surveillance test STP M-510-1 were reviewed. Pressurizer pressure and Thermal Margin/Low Pressure channel tests were performed on February 27, 1985 and May 25, 1985, using STPs M-210B-1 and M-210A-1 respectively. Their results were reviewed to verify the adequacy of the tests and trip setpoints. The test results were within the acceptance criteria of the station procedures and Technical Specifications.

Code Safety

The pressurizer code safety valves, RV-200 and RV-201, were tested on November 17, 1980, using the surveillance procedure, STP M-2-1. The following is a summary of the test results.

		Lift Setpoint, PSIG	
Valve	Rated Flow, lb/hr	"As Left"	Acceptance Range
RV-200	296,065	2493.5 2493.5 2493.5	2485 ± 25
RV-201	303,765	2551.5 2551.5 2551.5	2550 ± 25

The tests were performed in accordance with the station procedures.

8.1.4 Availability of Mechanical Components - HPSI/R

8.1.4.1 Scope

The review of mechanical components in the HPSI/R system primarily focused on components identified in the IREP study. These included:

- HPSI/R Pump #13
- SI-0405
- SI-0406
- SI-4144
- SI-4145

Each component was reviewed to ascertain that it would not cause loss of system function and that, if challenged, would function reliably.

8.1.4.2 Visual Inspection

Visual inspection consisted of an examination of the component and the area around the component valve. Support systems, such as HVAC and fire protection prevention systems were also examined to verify presence and type.

The HPSI/R Pump No. 13 and valves SI-0405 and 0406 are located in No. 12 ECCS Pump Room at Elevation -10 of the Auxiliary Building. Visual inspection of the pump and valves indicated no external damage, cleanliness problems, or indication of water leaks. Combustion sources in the area are limited.

8.1.4.3 Preventive Maintenance

The preventive maintenance review consisted of an examination of schedules and records for the past 2 years, a review of procedures, and interviews with personnel.

The following preventive maintenance procedures are related to the HPSI system:

Component Number	Procedure No.	Brief Description
No. 13 HPSI Pump Readings	1-52-M-2M-5	Vibration
No. 13 HPSI Pump	1-52-M-A-5	Change Bearing Oil and Inspect Couplings

A review of these procedures indicated that they were reasonably clear and technically adequate.

8.1.4.4 Corrective Maintenance

Corrective maintenance review consisted of an examination of records for the past 2 years, a review of procedures, and interviews with selected maintenance personnel.

The licensee is committed to the Administrative Section of the Technical Specifications, Regulatory Guide 1.33 and thus to ANSI 18.7 (1976). CCI-200I, "Nuclear Maintenance System", describes the overall maintenance program and the initiation of maintenance requests.

A review of the maintenance records indicated that only minor maintenance had been performed. The review indicated that the corrective maintenance had been performed per procedural requirements and that Technical Specification Requirements of Limiting Condition for Operation had been considered. A review of the procedures indicated that they were technically adequate.

The inspector discussed with the licensee whether they had any problems with the HPSI pump seal. A review of LER 79-41/31, discussions with the licensee, and review of corrective maintenance records indicated that this was not a repetitive problem.

3.1.4.5 Surveillar e

An inspection of surveillance records was conducted to verify the adequacy of the tests and results, and included a review of procedures, discussions with operators and a review of test results for several occurrences of the test.

Valves SI-4144 and 4145 along with the starting of HPSI Pump No. 13 are included in STP 0-65-1. The inspector reviewed this procedure and verified that the instructions were clear and technically sufficient.

8.1.5 Findings

No violations of NRC requirements or other deficiencies were observed.

Primary feed and bleed would only be used if all other mechanisms failed. It would not be an immediate action and operators would have plenty of time to decide whether or it was to be used. The procedure was adequate to accomplish bleed and feed, and equipment operational redundancy provides assurance that bleed and feed can be performed.

Emergency procedures require the Containment Sump valves to the HPSI pumps to be checked open on a RAS signal. There are sufficient backup methods to open the valves in case they fail to open automatically and operators are trained in their uses. This should minimize the chances of operator error in failing to open these valves.

8.2 Secondary Heat Removal Systems

8.2.1 Assessment of Steam Generator Feed and Bleed

8.2.1.1. Procedures

Numerous methods are available to assure secondary cooling of the primary plant using the steam generators. Water can be added to the steam generators via normal feed and condensate systems, or by the Auxiliary Feed Water System and Condensate Storage Tanks (CSTs). Heat is removed from the steam generators via the Main Steam and Condensate Systems, the atmospheric steam dumps, turbine bypass valves (BPVs) (which dump to the condenser) or the secondary safety relief valves (SRVs). The following procedures are available to the operator for cooling down the primary plant using various combinations of the above systems and components in normal, abnormal, or accident conditions. They are:

- OP-4, "Plant Shutdown From Power Operation to Hot Standby"
- OP-5, "Plant Shutdown From Hot Standby to Cold Shutdown"
- OI-11A, "Condensate System - Unit 1"
- OI-12A, "Feedwater System - Unit 1"
- OI-32, "Auxiliary Feedwater System - Unit 1"
- EOP-1, "Reactor Trip"
- EOP-2, "Loss of Reactor Coolant Flow/Natural Circulation"
- EOP-3, "Loss of Main Feedwater"
- EOP-4, "Steam Line Rupture - Unit 1"
- EOP-5, "Loss of Reactor Coolant"
- AOP-3D, "Loss of Auxiliary Feedwater"
- AOP-7F, "Loss of Load"
- AOP-7G, "Partial Loss of Condenser Vacuum"
- AOP-9, "Alternate Safe Shutdown Procedure 1, Control Room Evacuation - Unit 1"

Most procedures include automatic operation of valves and/or manual operation of valves from control panels.

8.2.1.2 Operational Features

This inspection covered components associated with bleeding steam from the steam generators and feeding the generators using the Auxiliary Feed System. AFW operations were previously discussed in Paragraph 3. Components covered by this section are limited to the bypass valves, atmospheric steam dumps and safety relief valves.

Atmospheric Steam Dumps

The two atmospheric steam dumps can be opened manually from the Control Room or Auxiliary Shutdown Panel. Loss of air will cause the valves to fail shut. There is a separate backup air accumulator for the atmospheric dumps which will allow continued operation on loss of control air. These valves can also be operated manually in the auxiliary building using a chain operator. The chain operators are readily accessible and properly identified.

Turbine Bypass Valves (BPVs)

There are four turbine bypass valves each with 10 percent capacity. The BPVs dump steam to the main condenser and depend on the availability of the condenser, condenser vacuum, and circulating water. They can be manually operated from the Control Room using their air operators. If the air fails, these valves will fail shut.

The BPVs are located in the turbine building, are easily accessible, and clearly marked. The valves have manual operators which can be used to open the valves should the air operators fail.

There is also a blocking valve for each BPV which is located adjacent to each BPV. Should any of these be shut, they can be easily opened manually.

Safety Relief Valves (SRVs)

There are sixteen safety relief valves which actuate on high pressure should the main steam isolation valves (MSIVs) close. The SRVs can relieve a total of 106 percent steam capacity. If the MSIVs close, the SRVs are the only means of removing steam (and heat) from the steam generators.

The SRVs are located in a group in a portion of the Auxiliary Building. Each SRV has a manual operator. However, the physical configuration is such that a specific SRV would be difficult to locate and manual operators would be difficult to operate.

8.2.1.3 Operational Simulation

Manual operators for the SRVs, BPVs, and steam dumps were physically located and observed. Manual operations of each valve was simulated by one plant operator to verify that manual local operation was feasible, should automatic or remote manual operation fail.

8.2.1.4 Training

Control room operators receive extensive training on plant cooldown and use of the control panels. All major operating, emergency and abnormal procedures are covered during this training. There are oral and written exams which include steam generator cooldown evaluation and a specific control room checkoff for knowledge of reactivity control manipulations.

Turbine building operators are given specific hands on training of turbine building equipment. There are specific examinations and practical factor checkoffs given for the Main Feedwater, Auxiliary Feedwater, Main Condensate, and Main Steam Systems. Operators must demonstrate their knowledge of valve location and operations.

Auxiliary Building operators are given training and examinations similar to that given for turbine building operators. There is a specific practical factors checkoff for steam generator (SG) and SG blowdown and recovery.

Operators must demonstrate their knowledge of operations. Lesson plans and checklists for turbine building and auxiliary building do not delineate the SRVs, BPVs or steam dumps but appear to be comprehensive enough to assure that such valves would be included.

8.2.2 Secondary Pressure Relief System Valves - Maintenance Review

To relieve the steam pressure in the secondary side, there are four 10% capacity turbine bypass valves and two 2.5% capacity atmospheric dump valves, with a combined steam relief capacity of 45%. Also, sixteen Steam Generator safety valves are available to relieve the steam to the atmosphere.

Preventive maintenance cards were reviewed for S/G No. 11 and S/G No. 12 Atmospheric Dump Valve controls, performed October 17 and December 16 of 1984. Also, Post-maintenance tests per MR 1-83-201 were performed November 24, 1983 on turbine Bypass valves, and the valve lift tests, per preventive maintenance PM 1-83-1-R8, were performed. The results were acceptable.

The lift setpoint test records of Main Steam Safety valves were reviewed to ascertain that the "As Left" values were within the required acceptance criteria, and that the unacceptable setpoints were properly recalibrated in accordance with the station Maintenance Request (MR) requirements. The tests reviewed were performed October 1 through November 29, 1983 using STP M-3-1, and their "As Left" setpoints met the acceptance criteria. Several MRs were reviewed.

8.2.3 Findings

No violations of licensee requirements or other deficiencies were observed.

The operators receive extensive training in plant cooldown. Numerous means to bleed and feed the steam generators and associated procedures are available. Thus, the operator could perform plant cooldown by steam generator bleed and feed when required in an accident situation.

The evaluation of corrective maintenance indicates that failures are identified during surveillance test and preventive maintenance programs and appropriate actions are taken.

9.0 Human Factors Engineering

9.1 Equipment/Facility Identification

The following three items were noted as inadequately identified and collectively constitutes an unresolved item (317/85-03-05).

9.1.1 Building Equipment Room Doors

During the inspection, Calvert Cliffs personnel and NRC inspectors toured various areas of the Auxiliary Building to inspect equipment and perform simulated operations in the building. In one instance, CC station personnel entered what was thought to be the Unit No. 1 No. 12 ECCS Pump Room. A few minutes after entering the room, it was noted by observing labeling on equipment that the room entered was the Unit 2 ECCS pump room. Personnel then went to the intended ECCS pump room.

Further observations indicated that other Auxiliary Building rooms are not labeled as to designation of the room and specific unit. It appears that even experienced personnel could enter a room for other than the intended Unit. Calvert Cliffs management acknowledged the concern.

9.1.2 Breakers

While observing the weekly surveillance test, Procedure STP-0-90-1, "Breaker Lineup Verification", the following inconsistency and/or lack of identification was noted.

-- The Procedure page 3, item c. 480v system, identified breaker 52-10401, MCC-104 as "Local Feeder Breaker". The name plate on the Motor Control Center (MCC) refers to "Supply Breaker". Similarly for breaker 52-11401, MCC-114.

-- Identification name plates, with the breaker numbers, shown in the procedure were not on the following equipment.

- Breaker 52-10401, MCC-104
- Breaker 52-10401, MCC-114
- Breaker 52-10420, MCC-104
- Breaker 52-11420, MCC-114
- Battery Disconnect Switch 95-1203

9.1.3 AFW Motor-Driven Pump No. 13.

During a routine "walkdown" inspection of the plant features and equipment it was observed that the plant safety-related equipment was clearly identified by the numbers and labels. For the vital pumps and equipment, large plates or labels were posted conspicuously in addition to the small metallic and vendor supplied plates which were attached to the hardware.

The motor-driven AFW pump No. 13 did not have the identification label posted by the pump, contrary to the normal plant postings.

9.2 Operator Access to Key Card Locked Doors

During operational simulation in the Turbine Building, it was observed that certain rooms such as the Switchgear Rooms, the AFW Pump Rooms, and the Service Water Rooms, required operation of a computer operated key card lock. Operators are not issued keys to these doors. During periods when the computer is down, which happened several times during the inspection, operators must call for

a security guard to unlock the door or get a key from the Control Room. If emergency entry to these rooms is required, and the security computer is down, then entry may be delayed several minutes until a security guard with a key arrives to open the door.

Calvert Cliffs representatives stated keys were not issued to operators to minimize the number of keys available. They also stated their security procedures required the changing of locks on doors whenever a person who had been issued a key left the company.

9.3 Communications

As discussed in the section on for AFW cross-feeding operations, the key-locked switch has to be used in order to transfer the control operations of AFW from the control room to the auxiliary shutdown panel. Furthermore, AFW pump speed control valves have to be swapped and the Turbine Building operator must switch control air valves in the Service Water pump room. Since operators would be separated physically, communications between units, local panels and equipment rooms would be difficult, particularly during an emergency event.

10.0 Administrative Controls

The NRC staff reviewed, on a sampling basis, the following administrative procedures, and observed the implementation of the station administrative control procedures to ascertain that the requirements in the Section 6 of Technical Specification, ANSI N18.7 and Regulatory Guide 1.33, Appendix A were met.

- Calvert Cliffs Instruction 110B, "Calvert Cliffs Key and Lock Controls," March 8, 1985
- CCI 112F, "Safety Tagging," January 20, 1985
- CCI 104F, "Surveillance Test Programs," August 18, 1981, Change No. 19, March 8, 1985
- CCI 117D, "Temporary Mechanical Device, Electrical Jumper and Lifted Wire Control," October 18, 1984
- CCI 120C, "Calibration Program for Measuring and Test Equipment," October 5, 1981
- CCI 211D, "Preventive Maintenance Program"
- CCI 300F, "Calvert Cliffs Operating Manual," February 11, 1985
- CCI 603D, "Plant Operator Training and Qualification," June 22, 1983

10.1 Findings

Housekeeping was consistent with the station procedures and the physical plant was maintained in an excellent state, emergency lighting was generally good.

Tagging: Color-coded tags and chain-locks were observed during the inspection tours, and practices of safety tagging were discussed with the licensee representatives, including administrative procedures and electrical load lists. Tagging on the safety-related equipment was good.

Operational Alertness and Safety Initiatives: Based on discussions with the plant operators, observed safety initiatives on battery replacement and AK-2 type RPS trip breaker #5 repairs, it was concluded that the licensee initiatives and operational alertness were good.

QA/QC: During the RPS trip breaker maintenance work, a QC inspector was observed conducting surveillance checks on the procedure, data taking and work in progress. Also, the inspector noted that management response to the findings of the on-site "quality circle" were good.

Maintenance: During routine maintenance work near motor-driven AFW Pump #13, temporary filters were provided for the motor to prevent dust from getting into the motor. Several observations on maintenance activities indicated that the maintenance program is good.

11.0 Facility tours

The inspector observed Control Room Operations for shift turnover and log sheets, and facility operation in accordance with the administrative procedures and Technical Specifications. Several inspection tours of the plant facility were conducted to observe the pre-scoped activities, equipment tagging, lock-out, housekeeping, and plant operations. The areas toured included:

-- Auxiliary Building: ECCS pump rooms and equipment; MSIVs; AFWS valves; Main Stream Atmospheric Dump valves; CCWS Heat Exchangers and valves; HPSI pump; HPSI/R sump valve controls; Electrical Penetrations; Volume Control Tank; Salt Water System valves.
-- Control Room
-- Switchgear room and AFWS control panel
-- AFWS turbine-driven pump room.
-- Service Water System room: AFWS Pump No. 13, SWS Heat Exchanger.
-- Circulating Water Pump room: Salt Water Pump No. 13
-- Battery rooms No. 11 and No. 12
-- RPS trip breakers

Details are discussed in the corresponding appropriate sections of this report.

12.0 Unresolved Items

Unresolved items are matters about which more information is required to determine if it is a violation, a deviation or acceptable. Unresolved items are discussed in paragraphs 3.4.3, 4.4.2, 6.9, and 9.1.

13.0 Exit Meetings

The inspector met with the licensee representatives denoted in paragraph 1 on March 8, 1985, and March 15, 1985, and summarized the purpose, scope and findings of the inspection. The attendees are listed in paragraph 1 of the report details.

At no time during this inspection was written material provided to the licensee by the inspector.

Attachment

I Preventive Maintenance Records - Mechanical

	PMS No	Description	Date Completed
1.	1-36-M-SA-1	Torque Foundation Bolts on Auxiliary Feed Pump and Turbine No. 11 and No. 12	05/05/83
2.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	04/08/83
3.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	05/05/83
4.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	06/06/83
5.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	07/07/83
6.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	08/01/83
7.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	09/09/83
8.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	09/09/83
9.	1-36-M-A-1	Change oil for Auxiliar Feed Pump Tub No. 11	02/28/84
10.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	03/28/84
11.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	02/28/84
12.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	01/24/84
13.	1-36-M-SA-1	Torque Foundation Bolts on Auxiliary Feed Pump and Turbine No. 11 and No. 12	01/24/84
14.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	01/10/83
15.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	02/10/83

Attachment

	PMS No	Description	Date Completed
16.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	03/08/83
17.	1-36-M-SA-1	Torque Foundation Bolts on Auxiliary Feed Pump and Turbine No. 11 and No. 12	04/08/83
18.	1-36-M-M-1	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 11	
19.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	04/08/83
20.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	05/05/83
21.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	06/06/83
22.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	05/05/83
23.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	02/28/84
24.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	05/05/83
25.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	01/10/83
26.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	02/10/83
27.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	03/07/83
28.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	07/07/83
29.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	08/01/83
30.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	
31.	1-36-M-M-2	Lubricate bearing on Auxiliary Feed Pump and Turbine No. 12	

Attachment

II Maintenance Records - Mechanical

	MR No	Component		Date Completed
1.	P8508744	No. 11 AFW Pump		
2.	000812	No. 11 AFW Pump		
3.	M8500001	No. 11 AFW Pump		
4.	002560	No. 11 AFW Pump		
5.	0-84-5562AA	No. 11 and No. 12 AFW Pumps		09/17/84
6.	0-84-1746	No. 11 AFW Pump		05/18/84
7.	0-84-1895	No. 11 AFW Pump		03/28/84
8.	0-84-3055	No. 11 AFW Pump		06/20/84
9.	0-84-1401	No. 11 AFW Pump		03/21/84
10.	0-84-0897	No. 11 AFW Pump		02/03/84
11.	P-84-6847AA	No. 11 AFW Pump		10/26/84
12.	P-84-8317AA	No. 11 & No. 12 AFW Pump		12/31/84
13.	0-83-7039	No. 11 & No. 12 AFW Pump		10/22/84
14.	0-84-4392AA	No. 11 AFW Pump		08/29/84
15.	006200	No. 12 AFW Pump		
16.	P8408290	No. 12 AFW Pump		
17.	000459	No. 12 AFW Pump		
18.	002669	No. 12 AFW Pump		
20.	0-84-3056	No. 12 AFW Pump		06/01/84
21.	0-84-1422	No. 12 AFW Pump		03/07/84
22.	0-84-4413AA	No. 12 AFW Pump		08/29/84
23.	P-84-6848AA	No. 12 AFW Pump		10/26/84
24.	0-84-4262AA	No. 12 AFW Pump		07/31/84
25.	0-83-1844	No. 12 AFW Pump		07/08/83
26.	0-83-03600	No. 12 AFW Pump		04/27/83
27.	M-85-2046	No. 11 & No. 12 AFW Pumps	b.	
28.	M-84-0136AA	No. 12 AFW Pump	b.	10/30/84
29.	M-84-0135AA	No. 11 AFW Pump	b.	10/29/84
30.	M-84-2075	No. 11 AFW Pump	b.	04/04/84
31.	M-84-1702	No. 11 AFW Pump	b.	03/19/84
32.	M-84-0968	No. 11 AFW Pump	b.	10/22/84

Attachment

III Maintenance - Maintenance Request (MR) - Electrical

	MR No	Description	Dated.
1.	0-83-212	Battery 11 Bus Negative Ground	01/12/83
2.	0-83-356	Battery 11 Bus Negative Ground	01/13/83
3.	0-83-02087	Battery 11 Bus Positive Ground	03/21/83
4.	0-83-03664	Battery 11 Bus Negative Ground	05/13/83
5.	E-83-236	Spare NCX 1500 Battery Cell	07/19/83
6.	E-83-223	Battery Charger Labeling on Charger Load Sharing Reset Button	07/22/83
7.	E-83-257	Battery 11 Voltage Drop Between Cells	07/29/83
8.	M-83-6098	Battery 11 Replacement CWP 81-1039 E-1-1	08/11/83
9.	E-83-229	Battery 6 11 Keep Old Spares	08/11/83
10.	0-83-6267	Battery 11 Bus Negative Ground	08/22/83
11.	0-83-6224	Battery 11 Bus Positive Ground	08/23/83
12,	E-83-349	Battery Charger 11 DV Voltmeter Problem	10/07/83
13.	0-83-8037	Battery 11 Bus Negative Ground	12/01/83
14.	0-83-8197	Battery Bus Positive Ground	12/02/83
15.	0-83-8462	Battery 11 Bus Positive Ground	12/12/83
16.	E-84-176	Battery 11 Microohm Resistant Reading After Cleaning and Troqueing	09/20/84
17.	E-84-179	Battery 11 Cell 1, 30, 31, 60 Post Deformation Connection Problem	09/20/84
18.	E-84-2236	Battery Charger 14 & 22 Not Sharing Load	11/13/84
19.	000157	Reserve Battery Electrolyte Level Low	02/02/85
20.	1-83-004	1-CV-5163 No. 12 Cow HX outlet valve air regulator	01/21/83

Attachment

	MR No	Description	Dated.
21.	0-83-554	1SW-5163 No. 12 CCW HX Normal BU Outlet Valve Open Seconds Alert	01/21/83
22.	0-82-6118	1-SW-5170 Solenoid Leaking Air from Vent Caused by Dried Gaskets and O Rings, ASCO SN 55887A, Part No. 8320A26	02/08/83
23.	0-83-1508	HIC 2-CV-5210, 5206 Blown Fuse	02/18/83
24.	E-83-134	Salt Water Pump 13 Breaker Tripped	03/30/83
25.	0-83-4088	Salt Water Pump 13 Breaker failed to open control fuse blown	05/11/83
26.	0-83-5409	Salt Water PUmps 11, 12, 13, 21, 22, 23, air vent getting blocked	07/06/83
27.	0-83-5661	1-SW-5163 No. 12 CCW HS normal backup outlet limit switch problem	07/25/83
28.	0-83-5664	1-SW-5162 No. 12 CCW HX SW Inlet Valve Stroke Time Alert	07/25/83
29.	E-83-288	1-CV-3826 No. 12 CCW HX Discharge Valve Seal Tight installed improperly	07/29/83
30.	E-83-264	No. 12 SW PP Breaker 152-1405 failed to close from the control room	08/09/83
31.	E-83-315	No. 13 SW PP Breaker 152-1112 Spring Charger Motor did not energize when breaker was racked on the Bus	09/27/83
32.	E-83-322	No. 12 Salt water PP BK 152-1405 Damaged MH and MJ Mechanical Linkage MH Switch Block Damager Per PM-1-12-E-2R-1	09/28/83
33.	0-83-8026	No. 12 Salt Water Pump Failed to Start Per STP 0-7-1 Either Manual or ESFAS Auto Manual Trip Level Problem	11/26/83
34.	0-84-458	No. 13 Salt Water Pump BK 152-1412 Rack in Problem, Auxiliary Switch Actuator Bent	01/19/8
35.	1-84-10	1-CV-5206, 5160, 5210 Install air Jumper and Repair Tubing	01/30/84

Attachment

	MR No	Description	Dated.
36.	E-8500010	No. 12 Salt Water Pump Motor Disconnect Leads Remove Motor to be Sent Out-motor Windings Dirty	01/18/85
37.	E-83-94	Reactor Trip Switchgear and Breakers perform independent test of U/V trip and shunt trip for RTB 1-8 as required by 1EB 83-04	03/15/83
38.	E-83-97	Reactor Trip Switchgear and Breakers, perform independent test of U/V trip device for RTB-1-8	03/16/83
39.	E-83-102	Reactor Trip Breakers RTB-1, RTB-3, RTB-4, inspect mechanical trip function	03/17/83
40.	E-83-238	Reactor Trip Breakers TRB-3, RTB-4, breaker did not trip instantaneously while performing STP-M-200-1	07/18/83
41.	E-83-237	Reactor Trip Breaker RTB-6, failed to trip when depressing emergency trip push button while doing STP-M-200-1	07/18/83
42.	E-83245	Testing inspection per FTE-57 RTB1-8	07/26/83
43.	I-23-254	Reactor Trip Breakers RTB-3, RTB-4, RTB-6 would not close when reset by control switch in the control room	08/08/83
44.	E-83-313	Reactor Trip Breaker inspect RTB1-8, PM-1-58-E-A-1 with vendor supervision	10/06/83
45.	0-83-4918	Reactor Trip Breaker RTB-3, handswitch 1C15 control room problem	11/04/83
46.	E-83-457	Reactor Trip Breaker RTB-6, will not close	11/28/83
47.	D-83-08154	Reactor Trip Breaker RTB-1 trip coil light problem	11/28/83
48.	E-83-489	Reactor Trip Breaker RTB-2, while performing STP M200-1 out of spec >200 ms	12/22/83
49.	E-83-492	Reactor Trip Breaker RTB-3, replace front frame assembly	01/05/84

Attachment

	MR No	Description	Dated.
50.	R-84-10	Reactor Trip Breaker RTB-9, response time test	01/14/84
51.	0-84-714	Reactor Trip Breaker RTB-3 will not close after matrix test STP-0-6-1	04/05/84
52.	E-84-023	Reactor Trip Breaker RTB1-8 inspect Z shape clamp on U/V device per operating experience 946	01/13/84 01/31/84
53.	E-84-2.5	Reactor Trip Breaker RTB-9 (RTB-3 comp) U/V trip problem	01/31/84
54.	E-84-72	Reactor Trip Breaker RTB-2, RTB-5, RTB-7, inspect closing armature problem	04/05/84
55.	E-84-7B	Reactor Trip Breaker RTB-2, replace front frame assembly	04/07/84
56.	E-84-0074	Reactor Trip Breaker RTB1-8, inspect shut trip clamp	04/07/84
57.	0-84-1824	Reactor Trip Breaker RTB-6, would not close after STP-M-210B-1	06/28/84
58.	E-84-126	Reactor Trip Breaker RTB-6, broken lug on wire to local emergency shunt trip push button	08/28/84
59.	E-84-182	Rector Trip Breaker RTB-5, U/V device problem	09/28/84
60.	E-85-002	Reactor Trip Breaker RTB-1, replace front frame assembly	01/03/85
61.	E-85-003	Reactor Trip Breaker RTB-4, replace front frame assembly	01/04/85
62.	E-85-12	Reactor Trip Breaker RTB-7, blown fuse	01/19/85
63.	000737	Reactor Trip Breaker Unit 2, RTB-5, replace closing coil and front frame assembly	03/05/85

	MR No	Description	Attachment Dated.
64.	E-83-235	No. 12 HPSI Pump Breaker 152-1408 operation counter and open close indication problem	07/28/83
65.	E-84-097	Safety Injection High and Low pressure pump motors install temporary filters on ventilation to protect motor during sandblasting	05/29/83
66.	0-83-1883	No. 11 HPSI Pump Motor Breaker charging spring would not charge due to close latch switch sticking	03/10/83
67.	0-84-1543	No. 11 HPSI Pump Motor Breaker hard to rack in. No problem found	05/31/84
68.	0-84-2809	No. 12 HPSI pump motor breaker hard to rack in. No problem found	05/31/84
69.	X-84-134	ESF room 11 fan cooler per PM 152-I-R02-37 found problem with room thermostat and replaced.	06/05/84