UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-259/92-05, 50-260/92-05, and 50-296/92-05

Licensee: Tennessee Valley Authority
6N 38A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

Docket Nos.: 50-259, 50-260, and 50-296

License Nos.: DPR-33, DPR-52, and DPR-68

Facility Name: Browns Ferry Units 1, 2, and 3

Inspection at Browns Ferry Site near Decatur, Alabama

Inspection Conducted: February 15 - March 13, 1992

Inspector: _____ 4/2/92
C. A. Patterson, Senior Resident Inspector Date Signed

Accompanied by: E. Christnot, Resident Inspector
W. Bearden, Resident Inspector

Approved by: _____ 4/2/92
Paul J. Kellogg, Chief Date Signed
Reactor Projects, Section 4A
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection included surveillance observation, maintenance observation, operational safety verification, engineered safety feature system walkdown, control room emergency ventilation system test failure, modifications, Unit 3 restart activities, reportable occurrences, and management changes.

Results: Unit 2 successfully conducted a maintenance outage, paragraph four. A strength was noted in outage planning. Outage meetings were conducted several times a day with backshift management coverage. The licensee displayed the proper sensitivity to shutdown risk implementing the NUMARC guidelines. The licensee resolved repair methodology with NRR and Region II for repair of two valves in the drywell.

Unit 3 schedule update to factor in the walkdown data was not performed on March 7, 1992, paragraph eight. Walkdowns continue in the electrical area with a Level II schedule update planned one month after the original date.

An inspector followup item was identified concerning the use of the Unit 2 restart criteria for Unit 3, paragraph eight. The licensee stated the criteria was used in an informal management

assessment of contractor activities. The inspectors requested clarification of the process for Unit 3. Several meetings attended during the period were ineffective. Management was taking action to improve these meetings.

A test was conducted to determine the capacity for the control room emergency ventilation system fan, paragraph six. The test failed due to gross inleakage in the control building. Resolution of the capacity question and ducting sealing have not been determined. Final corrective actions to return the control room emergency ventilation system to a fully operational status continue to be delayed

One phase of the Unit 1 main transformer shorted and was damaged significantly, paragraph four. A spare transformer is being connected in the switchyard. Additional controls were placed on switchyard access prior to starting this work.

REPORT DETAILS

1. Persons Contacted

Licensee Employees:

*O. Zeringue, Vice President, Browns Ferry Operations
*H. McCluskey, Vice President, Browns Ferry Restart
*J. Scalice, Plant Manager
*J. Swindell, Restart Manager
*M. Herrell, Operations Manager
J. Rupert, Project Engineer
*M. Bajestani, Technical Support Manager
R. Jones, Operations Superintendent
A. Sorrell, Maintenance Manager
*G. Turner, Site Quality Assurance Manager
R. Baron, Site Licensing Manager
*J. McCarthy, Unit 3 Licensing
*P. Salas, Compliance Supervisor
J. Corey, Site Radiological Control Manager
*A. Brittain, Site Security Manager

Other licensee employees or contractors contacted included licensed reactor operators, auxiliary operators, craftsmen, technicians, and public safety officers; and quality assurance, design, and engineering personnel.

NRC Personnel:

P. Kellogg, Section Chief
*C. Patterson, Senior Resident Inspector
*E. Christnot, Resident Inspector
*W. Bearden, Resident Inspector

*Attended exit interview

Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Surveillance Observation (61726)

The inspectors observed and/or reviewed the performance of required Sis. The inspections included reviews of the Sis for technical adequacy and conformance to TS, verification of test instrument calibration, observations of the conduct of testing, confirmation of proper removal from service and return to service of systems, and reviews of test data. The inspectors also verified that LCOs were met, testing was accomplished by qualified personnel, and the Sis were completed within the required frequency. The following SIs were reviewed during this reporting period:

a. 2-SI-4.2.B-20(B)FT, RHR Pump Discharge Pressure Functional Test. This test demonstrates operability of the Unit 2 RHR Pump Discharge Pressure Switches 2-PS-74-31A, 2-PS-74-31B, 2-PS-74-42A, and 2-PS-74-42B. This test is intended to satisfy requirements specified in TS Table 4.2.B. These pressure switches provide a blowdown permissive signal to the ADS System whenever the respective RHR pump discharge pressure is greater than or equal to 100 psig. The inspector reviewed the documentation associated with the two most recent performances of this surveillance requirement. This test is required to be performed monthly and

was last performed on January 21, 1992 and February 18, 1992. During the performance of step 7.7.8 of the SI on February 18, 1992, Pressure Switch, 2-PS-74-31A, failed to operate until 140 psig. The proper band is 108 to 110 psig. Additionally the actuation signal would not reset when the pressure was decreased. This problem was later determined to be due to a faulty snubber in the instrument line. The problem was corrected and the SI reperformed on the same date with satisfactory results.

During the above review for the test performed on February 18, 1992, the inspector noted that the test was conducted as a validation run. Since several administrative errors were identified during that performance which were documented as part of the validation process the inspector questioned why these errors were not identified at the earlier performance of the same SI. The inspector was informed by the licensee that the same errors had also been identified during the performance on January 21, 1992, but that Form SSP-4 which is used to track SI validations had not had sufficient time to allow revision yet. The Instrumentation Technician that performed the later SI did not know about the earlier validation and reperformed the validation process. Since the errors were associated with steps of the procedure that are not performed under the current system configuration (standby readiness) and did not affect the ability to correctly perform the test the inspector concurs with the licensee's decision to complete the test without first requiring a procedure revision. Based on this and other recent reviews of SIs the inspector determined that this problem with validation of the SI was an isolated case. The inspector did not identify any other deficiencies with the completed surveillance tests.

b. 2-SI-4.2.B-ATU(A) Core and Containment Cooling Systems Analog Trip System Functional Test. This test checks various ATUs in the Unit 2 Auxiliary Instrument Room as required by T.S. Tables 3.2.B and 4.2.B. This is a monthly surveillance and checks the Reactor Water Level, Reactor Low Pressure, Reactor High Pressure, and Drywell High Pressure ATUs located on the 2-P-9-81 panel. The inspector observed portions of this ongoing testing performed on March 5, 1992, in the Unit 2 Auxiliary Instrument Room. The inspector did not identify any deficiencies with the completed surveillance test.

c. 2-SI-4.2.C-3(C), Instrumentation That Initiates Rod Blocks/Scrams IRM Channel C Calibration. The surveillance is required to be performed quarterly and is intended to satisfy requirements from TS Table 4.2.F. The inspector observed portions of this test performed in the Unit 2 Control Room on March 5, 1992. The inspector did not identify any deficiencies with the completed surveillance test.

No violations or deviations were identified in the Surveillance Observation area.

3. Maintenance Observation (62703)

Plant maintenance activities were observed and/or reviewed for selected safety-related systems and components to ascertain that they were conducted in accordance with requirements. The following items were considered during these reviews: LCOs maintained, use of approved procedures, functional testing and/or calibrations were performed prior to returning components or systems to service, QC records maintained, activities accomplished by qualified personnel, use of properly

certified parts and materials, proper use of clearance procedures, and implementation of radiological controls as required.

Work documentation (MR, WR, and WO) were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which might affect plant safety. The inspectors observed the following maintenance activities during this reporting period:

a. Recirculation Motor Generator Set 2A Inspection

An inspector observed various activities associated with WO 92-48015-00 on February 23, 1992. This WO was issued to remove the 2A recirculation MG fluid coupler top cover and perform various inspection activities. Due to recent problems which were identified with the 2B recirculation MG fluid coupler the licensee decided to perform this inspection on the 2A MG Set during the first available outage. Problems that had been found on the 2B MG set included misalignment of the scoop tube positioner and rust buildup on various surfaces within the fluid coupler.

The 2A recirculation MG set was removed from service and placed under Hold Order 2-92-109. The inspector observed the lifting of the top cover and inspection of the fluid coupler internal components. The scoop tube positioner was disconnected and manually operated by maintenance supervisory personnel to verify that no binding existed. The internals were inspected for signs of improper alignment, wear, and physical appearance. Although limited work was authorized under this work order to allow removal of light rust and alignment adjustments no actual work was needed due to the licensees determination that the internals were in better physical condition than that observed during the 2B recirculation fluid coupler inspection. The inspector observed that maintenance personnel were ensuring that no objects could be dropped into the open fluid coupler by establishing controls required in accordance with SSP-12.8, Foreign Material Exclusion. The inspector did not identify any problems with the licensee's inspection of the fluid coupler.

b. Deficiency Tag on Diesel Generator Heat Detectors

An inspector noted an equipment deficiency tag during a routine tour of the Unit 1/2 D/G building on March 3, 1992. The tag referenced WR 038611 and stated that heat detectors 0-TS-39-10E and 0-TS-39-10A had failed on February 15, 1992. These heat detectors provide automatic CO2 fire protection actuation for the 1/2 "D" D/G room and are required to be operable by T.S. Table 3.11.A. Since no hourly firewatch was covering the area and no active LCO was shown on the current Plan of The Day LCO List the inspector requested that operations personnel review the status of these heat detectors. The inspector was informed that the problem with these heat detectors had been corrected on February 18, 1992, and maintenance personnel had inadvertently failed to remove the equipment deficiency tag when the heat detectors were returned to service. The inspector was further informed that the failed heat detectors were originally identified during performance of routine surveillance testing in accordance with 1/2-SI-4.11.D.1.b, Unit 1 and 2 D/G building CO2 system functional test. This condition had been tracked under LCO 0-92-16-3.11.D which was exited on February 21, 1992, following completion of the surveillance test. The inspector was further informed that the required firewatch had been established under that LCO and the respective Attachment F.

The inspector verified that the above fire protection impairment had been covered under Attachment F Number 92-0044-003. The inspector reviewed completed WO 92-49092-00 which was issued to repair these heat detectors. During this review the inspector noted that the only work performed was cleaning of relay contacts which corrected the above problem. The inspector did not identify any problems with this review other than failure to remove the equipment deficiency tag.

c. Snubber Material Problem

The inspector reviewed completed WO, 92-49156-00, which was issued to troubleshoot and repair the RHR pump 2B discharge PS, 2-PS-74-31A. This PS is designed to provide a "LPCI Pump Running" blowdown permissive signal to the ADS system whenever the RHR pump has a discharge pressure greater than 100 psig. During performance of routine surveillance 2-SI-4.2.B-20(B)FT, RHR Pump Discharge Pressure Functional Test, the pressure switch had failed to operate until 140 psig. The proper band is 108 to 110 psig. Additionally the pressure switch failed to reset after the pressure was reduced. This problem was later determined to be due to a plugged snubber in the instrument line. The snubber was replaced and the SI reperformed satisfactorily. The licensee documented the failure of this instrument to perform as expected under Problem Evaluation Report, BFPER920016. According to this evaluation the defective snubber contained an internal star washer possibly made of a material other than stainless steel. The washer became oxidized and restricted flow. The inspector did not identify any problems with this maintenance activity. The licensee replaced all (24) of the snubbers on safety equipment during the outage.

d. Rod Block Monitor Failure

WOs 92-49854-00 and 92-49854-01, were issued to troubleshoot and repair the problem with the RBM system. Following the Unit 2 startup from the outage on March 2, 1992, at 3:35 a.m. prior to reaching 30% power the "A" RBM was declared inoperable due to too few inputs sensed with adequate inputs available. The licensee was unable to reproduce the condition and RBM "A" was declared operable following performance of the functional test. However, on March 3, additional problems appeared which affected both channels. The K-2 contacts appeared to tie A & B detectors together regardless of which rod was selected. Both RBM channels were then declared inoperable. The SOS directed that A RBM Mode switch be placed in STBY position to insert trip per T.S. This resulted in a control rod withdrawal block and power ascension was halted. After further investigation the licensee found a bent pin in the RBM "A" J47 connector. This problem resulted in shorting two pins together. The affected pin was straightened and this corrected the problem. The licensee believes that the earlier problem that could not be reproduced was due to a possible stuck relay in the control rod selection matrix circuity. That condition has not recurred since being observed on March 2, 1992. The inspector did not identify any problems with this maintenance activity.

During the outage the inspectors followed licensee activities associated with repairing various identified drywell leaks and balance of the Unit 2 turbine generator.

No violations or deviations were identified in the Maintenance

Observation area.

4. Operational Safety Verification (71707)

The NRC inspectors followed the overall plant status and any significant safety matters related to plant operations. Daily discussions were held with plant management and various members of the plant operating staff. The inspectors made routine visits to the control rooms. Inspection observations included instrument readings, setpoints and recordings, status of operating systems, status and alignments of emergency standby systems, verification of onsite and offsite power supplies, emergency power sources available for automatic operation, the purpose of temporary tags on equipment controls and switches, annunciator alarm status, adherence to procedures, adherence to LCOs, nuclear instruments operability, temporary alterations in effect, daily journals and logs, stack monitor recorder traces, and control room manning. This inspection activity also included numerous informal discussions with operators and supervisors.

General plant tours were conducted. Portions of the turbine buildings, each reactor building, and general plant areas were visited. Observations included valve position and system alignment, snubber and hanger conditions, containment isolation alignments, instrument readings, housekeeping, power supply and breaker alignments, radiation and contaminated area controls, tag controls on equipment, work activities in progress, and radiological protection controls. Informal discussions were held with selected plant personnel in their functional areas during these tours.

a. Plant Status

On February 22, 1992, the unit was removed from service for a planned outage. Prior to the outage, the unit operated continuously for 73 days. Two major outage items were to rebalance the main turbine to reduce vibration and identification of drywell leakage. The outage work was completed and the unit returned to service on March 2, 1992. The outage was one day longer than planned due to repair of several leaks in the drywell.

b. Outage

Overall the outage was well planned and conducted with proper sensitivity to shutdown risk. The licensee implemented the NUMARC guidelines for shutdown risk. This was referred to as TS requirements plus one. For example, if TS required one pump for water makeup to the reactor vessel then two were maintained by the guidelines. Outage meetings were conducted several times a day with backshift management coverage. The licensee worked closely with NRR and Region II for resolution of two valve repairs in the drywell. The inspector concluded that outage planning was a strength for the licensee.

1) Waiver of Compliance

On February 29, 1992, the NRC granted a regional waiver of compliance. This was granted to permit repair of a leaking RHR valve. TS 3.5.B.9 does not explicitly identify the manual realignment of RHR for Shutdown Cooling to LPCI mode as acceptable in Cold Shutdown for operability considerations.

To perform the valve repair, one loop of RHR must be

isolated and the other loop aligned for Shutdown Cooling. To permit the valve repair with both RHR loops not aligned for LPCI mode, several compensatory measures were required.

(a) Both CS Loops were maintained operable

(b) RHR Loop II was capable of being manually realigned from SD cooling

(c) Training and procedures were provided to the operators to ensure that manual realignment could take place.

The inspector verified the compensatory measures while the waiver was in effect. The work was accomplished within the 60 hour time limit. Live time training was conducted for the operators on the waiver, AOI-74-3, and ARP for a RHR pump trip. The inspector reviewed the training attendance signature sheets. All conditions of the waiver were met.

2) Shutdown Cooling Manual Isolation Valve (74-49) Repair

The licensee make a code weld repair to a manual isolation valve. This valve is located between the reactor vessel and the two MOV SD cooling suction isolation valves. The repair was first performed on Unit 3. A repair was then performed on Unit 2. The details of the valve repair, procedures, and observation are documented in a regional office inspection report 92-08.

c. Light Bulb Replacement Causes ESF Actuation

On March 2, 1991, an ESF actuation was received on Unit 1 due to RPS circuit protector 1B1 de-energizing while a light bulb in its control circuit was being replaced. This caused a loss of RPS B and resulted in group 6 and 2 PCIS actuation. Due to the shut down defueled extended outage condition of Unit 1, the action was limited to: reactor building and refuel zone ventilation isolation; A, B, and C standby gas treatment trains starting; A and B CREV start; and, drywell equipment and floor drain outboard isolation valves closing. All required alarms and equipment actuations were properly received.

This apparent cause of the 1B1 circuit protector de-energizing was a loss of control power caused by a shorting out of the light bulb socket while its bulb was being changed. The actual fault appeared during the removal of a burned out light bulb. The inspector reviewed a modification DCN W5672, see modifications paragraph as part of the followup to this ESF actuation.

d. APRM Problems

On Feb. 21, 1992, the licensee identified that all three APRM Hi flux flow biased trip channels had experienced a similar failure which resulted in multiple trip channels in the same trip system being inoperable simultaneously. "A" and "C" APRM Hi HI Thermal trips were all found to be inoperable due to welded contacts on the K19 relays. "E" APRM was also found to have the same problem with the contacts on the K19 relay but an "A" RPS trip would still occur due to a slightly different design. The licensee evaluated this condition and determined that it would be reportable under 10 CFR 50.73(a)(2)(i)(B).

The licensee's design includes the use of a single flow converter associated with three APRM channels for each or the two RPS trip systems. "A" RPS is associated with the "A" Flow Converter and the "A", "C", and "E" APRMs.

The licensee conducted an investigation to determine the cause of this multiple failure. As the result of this investigation the licensee determined the following:

> On Feb. 8, 1992, during repairs to the "A" APRM mode switch a 1/2 scram had occurred on the "A" RPS channel. The cause was determined to be due to use of a soldering iron without an isolation transformer, i.e. grounded power source. This resulted in grounding the "A" flow converter channel output (inputs to A, C, and E APRMs). Work was completed with an isolation transformer after the 1/2 scram was reset and applicable portions of 2-SI-4.2.C-1(A), Flow Converter Calibration & Functional Test, performed and no test deficiencies were identified. The licensee's investigation into this separate event had attributed it to an inadequate procedure which did not warn against soldering without using an isolation transformer and inadequate training of maintenance personnel.
>
> On Feb. 14, 1992, 2-SI-4.2.C-1.1FT, APRM Functional Test, was performed at normal weekly periodicy, no test deficiencies were identified. This test demonstrated operability of all K19 relays in the APRM System.
>
> On Feb. 15, 1992, RPS "A" received a 1/2 scram from "A", "C", and "E" APRMs due to degraded voltage output from flow converter "A" power supply. Output voltage was running about 70% which corresponded to a Hi Hi thermal trip setpoint for the existing power level of 100%. The power supply remained in this degraded condition for approximately eight hours until it was replaced. Applicable sections of 2-SI-4.2.C-7(A-1), Flow Bias Instrument, and 2-SI-4.2.C-7FT, Flow Bias Instrument Functional Test, were performed with no test deficiencies. These tests were performed as post maintenance tests to demonstrate operability of the flow converter power supply but would not have identified a problem with the K19 relays.

During a subsequent investigation the licensee determined that the multiple relay failures resulted from the degraded flow converter output voltage condition that had existed for an extended time period. The licensee also determined that the earlier soldering event that occurred on Feb. 8, 1992, was not a factor in the failure of the K19 relays. This is based on a failure determination that grounding the flow converter output could not have caused the power supply degradation. The commonality of the flow converter to all three APRMs caused the relays to experience simultaneous failure. Although a RPS trip signal does seal in the K19 relays do not seal in. The relays were probably subjected to chattering under load and this condition can result in contact damage. Subsequent review by the licensee of the First Out Recorder printouts confirmed that a 1/2 scram did occur during the flow converter post maintenance test performed on Feb. 15, 1992. However the 1/2 scram occurred due to the APRM "E" trip in the A2 Channel only. The "A" and "C" APRM channels did not provide a trip signal. APRM Channel "E" has a slightly different design which uses an additional slave relay, K23, between the K19 and RPS HFA

relays. The licensee disassembled two of the failed K19 relays and found the contacts to be burned and welded closed due to overheating.

The inspector was informed by the licensee that post maintenance testing performed on Feb. 15, 1992, did not include a functional test of the APRM channels because licensee personnel did not see a direct relationship between the degraded voltage condition of the flow converter power supply and the APRM relays which utilize separate power supplies. As the result the specified post maintenance testing only included testing of the flow converter.

As the result of this event the licensee has identified two corrective action items that are scheduled to be completed by April 26, 1992. These items are as follows:

> Evaluation of the current design of the HI HI Thermal Trip to determine if contact ratings are adequate and if re-design to eliminate the common mode failure is warranted.
>
> Revision of plant procedures to assure that appropriate testing is performed if a similar situation occurs.

Additionally the inspector was informed by licensee management that a memo would be sent to affected personnel that covered this problem and reinforced the requirement to ensure that identified post maintenance testing was appropriate for the work performed. However the licensee does not consider the post maintenance testing following replacement of the flow converter power supply to have been inadequate since there was no reason to know that the K19 relays had failed. Additionally the affected RPS trip system was still capable of generating a scram signal due to the slightly different design on "E" APRM.

The inspector reviewed portions of 2-SI-4.2.C-7FT which was performed as one of the two post maintenance test conducted on Feb. 15, 1992. The inspector determined that this procedure contains in steps 7.6.4 and 7.7.41 signoffs to notify the unit operator prior to a 1/2 scram and for resetting of that 1/2 scram. Based on this review and the review of the licensee's First Out printout for Feb. 15 shows that a 1/2 scram was received, the inspector determined that the licensee's conclusion that adequate post maintenance testing had occurred was reasonable considering the information available at the time.

e. Spent Fuel Pool Transfer Canal

The inspector reviewed with operations personnel routine checks made of the transfer canal to avoid draining of the spent fuel pools. In IR 92-03 a violation was issued because the transfer canal gates were not properly installed. In procedure 0-GOI-300-1, Operations Routine Sheets, the fuel pool liner drain valve and transfer canal expansion joint are checked for leakage. The expansion joint is between Unit 1 and Unit 2.

f. Unit 1 "B" Phase Main Transformer Failure

On March 5, 1992, the high side of the Unit 1 "B" phase main transformer shorted to ground and an explosion occurred. The cabinet doors were blown open, pieces of porcelain fell to the ground, and oil ran down the side of the transformer. The transformer sprinkler system activated immediately and no fire

resulted. The plant fire truck and brigade responded. Unit 2 was operating at the time and due to the many sources of offsite power remained operating normally.

The licensee had experienced an annunciator alarm in the Unit 1 control room titled "Transformer Gas Pressure High or Low", window 14 on 1-XA-55-8A on panel 9-8. This had occurred on February 11, 1992. A work order was written to check the alarm. The work revealed a ground on the cable that runs between the Unit 1 "A" phase main transformer and terminal cabinet 1 located in the transformer yard. The terminal cabinet and associated wiring and terminal blocks were observed to be wet from condensation. Excessive corrosion and pitting were observed on the terminal blocks and screws in the terminal cabinet. Work requests were written to correct the problems.

The transformer gas pressure high or low alarm on the "A" Phase Unit 1 transformer is paralleled with the same alarms on "B" phase and "C" phase Unit 1 main transformers in terminal cabinet 1 located in the transformer yard. During trouble shooting the "A" phase wire was lifted so a valid alarm from one of the other transformers would not be masked. From initial discussions with control room operation the inspector learned that a "B" phase alarm had come in the day before and the paperwork for disabling the "A" phase was being completed. However, there was some discussion about which wire had been actually lifted. The licensee is conducting an incident investigation of the event. The inspector will review this once completed.

The inspector discussed with the licensee that common annunciators are not counted in the plant daily report. Other annunciators such as CST level are in high alarm due to conflict between the alarm reset band width and required level. More attention needed to be directed toward annunciators besides the main control board.

The licensee is connecting a spare transformer in the switchyard. Prior to commencing the work, additional controls were established. A licensed operator was placed in charge of the work and granted access to the area. All the gate locks were changed and placed under operations control. All personnel working on the job were briefed on recent industry switchyard events.

5. ESF System Walkdown (71710)

The inspector walked down selected portions of System 63, Standby Liquid Control. During the walkdown the inspector verified that the current configuration and lineup of handswitches on control room panels was that required to support standby readiness as defined in OI-63, Standby Liquid Control. Additionally the inspector noted the position of accessible valves, instrumentation, and general housekeeping locally near the SBLC components. No problems were identified.

6. CREV Test Failure

During the outage on February 24, 1992, a special test (O-ST-91-07) of the CREV was conducted. The purpose of the test was to determine if the CREV is adequately sized to pressurize the CBHZ. The test was conducted by pressurizing the CBHZ to 1/8 inch positive water pressure and determining the leakage in cfm from the CBHZ. This was performed using a test fan capable of 4500 cfm, isolating the CBHZ, and shutdown and isolation of all of the supply and exhaust fans which provide ventilation air to and from the outside for each elevation of the

control bay building.

The present capacity of the CREV A and B fan is 500 cfm. It was expected that flow of 1000 cfm would be sufficient. However, after the flow reached 2840 cfm during the test, the test was stopped. Numerous leakage paths must be corrected and the test performed again. Sufficient capacity is only one of the problems with the CREV system.

In the NSRB minutes of December 12, 1991, the unfiltered air leakage problem was discussed. CREVs alternatives are still being evaluated, and another postponement for identification of specific action was made until May 1992. The most important contributor to control room dose due to the 2,750 cfm of unfiltered air leakage is the postulated fission product gas (primarily iodine) path through both MSIVs turbine seals, and turbine roof. The calculated dose is now 275 REM, which is nearly 10 times the allowable 30 REM dose.

Several options are under consideration. One option is the replacement of existing air ducts with welded ducts in the control bay. This will require major modifications and building a false ceiling in the control room. A second option is sealing of existing ducts with a non-toxic, sprayed latex material applied by a robotic device. This is being tested at a local test laboratory.

The licensee was granted a one cycle TS approval for the CREV being technically not operable because it does not meet its design basis. The final resolution of these problems continues to be delayed. Two problems must be resolved. One is adequate capacity of the fans. The other is control of the unfiltered air leakage. The inspector will continue to follow these problems until resolved.

7. Modifications (37700, 37828)

The NRC inspector reviewed and observed the Unit 2 modification activities. This included review of procedures, discussions with craft, QC inspectors, supervisors, and managers, observation of field activities, and reviews of WPs and DCNs. The reviews and observations consisted of the following:

a. Design Change Notices

The inspector reviewed DCN W17480A, Install Additional Relay and Logic to Prevent Generator Trip Due to Opening of a Single PT Fuse; DCNs W5627A, 5628A, and 5629A, Install Isolation Fuses to Prevent Loss of RPS Due to Indicating Lamp Short Circuits; and DCN W17056A, Install Water Backflow Preventors in the Plant Potable Water System.

b. DCN In-Depth Reviews

The inspector performed an in-depth review of DCNs W17480A and DCN 5627A. DCN W17480A was issued to add a second generator backup relay with its potential sensing circuit supplied from the switchyard 500 KV bus 2, section 2 potential transformer. A new 3-pole fuse block and fuses on the potential transformer secondary were required for circuit protection. The new generator backup relay current sensing circuit were to be connected in series with the existing generator backup relay in the existing 500 KV transformer high side current transformer circuit. Special blocks in the current transformer circuit were installed to allow removal of either generator backup relay. A new timer, was added with a

ten cycle setpoint downstream of the new generator backup relay, and two new electrically tripped, hand reset, relays to be tripped by the existing timer and the new timer were added. When the relays operate, annunciation warns the operators that a relay operation has occurred. The contacts of the timers were to be arranged in a two-out-of-two logic scheme to require operation of both channels of generator backup relaying before relay 286TF is tripped, which in turn trips the unit. Two new relays to multi-pole breakers 5244 and 5248 position indicating contacts were added. The contacts were arranged to require operation of both generator backup relay channels to trip the unit when breakers 5244 and 5248 are closed, and to allow one channel of generator backup relaying to trip the Unit when either of those breakers is open. Trip cutout switches would allow for testing relays or temporarily removing them from service without tripping the unit or affecting the operation of the remaining channel of generator backup relaying. All modifications were at the panels in the relay room on the control bay operating room floor, and no cables or cable raceway modifications were involved. The new equipment was mounted in relay room panels 32 and 35.

DCN W5627A was issued because the existing design of RPS Circuit protector is such that the indicating lamps and sockets are susceptible to physical impact. Also, the circuit protector fusing is that a shorted bulb/socket de-energizes the entire cabinet causing loss of the RPS cabinet. This modification will provide isolation fuses which will prevent loss of the RPS main fuse due to a lamp short circuit. The circuit protector relays have no means to aid post-evaluation of circuit protector operation. This modification will provide latching relays to capture the trip cause until the circuit reset is activated. The inspector noted that DCN W5627A was issued for Unit 1, DCN W5628A for Unit 2 and DCN W5629A was issued for Unit 3.

c. Field Observations

During the forced outage the inspector reviewed and observed the licensee's activities associated with the implementation of DCN W17480A. The implementing work document was WP 2021-92, and the DCAs reviewed were 17480-005, 007, 015, 016, 018, and 021. The inspector noted that the WP was at the work site, the modifications engineer was overviewing the work activities, TVA QA was present, and when called the NE design engineer was at the work site. Additional field observation activities included the change out of steam flow Rosemount Transmitters and instrument sensing line snubbers. All observed work activities were performed in accordance with approved drawings, instructions, and procedures.

The inspector concluded from these observations and review that the Unit modification activities were being performed in a controlled, approved manner and in accordance with site procedures.

8. Unit 3 Restart Activities (30702)

The inspector reviewed and observed the licensee's activities involved with the Unit 3 restart. This included reviews of procedures, post-job activities, and completed field work; observation of pre-job field work, in-progress field work, and QA/QC activities; attendance at restart craft level, progress meetings, restart program meetings, and management meetings; and periodic discussions with both TVA and contractor personnel, skilled craftsmen, supervisors, managers and executives.

a. Control Room Design Review

The inspector observed and reviewed the activities associated with the BFN CRDR. The licensee designated a SWEC engineer as the Unit 3 Control Room Project Manager with both Bechtel and SWEC personnel reporting to the engineer. The inspector noted and reviewed the first Unit 3 CRDR DCN for Panel 3-9-3. This DCN required some relabeling and changes in light color and location. Additional DCNs due for issuance during March, 1992, included DCNs W17045, 17043, and 17040 for panels 3-9-2, 3-9-10, and 3-9-9. The inspector will continue to observe and review the work activities for CRDR.

b. Ineffective Meetings

1) POD

On February 26, 1992, the inspector attended the Unit 3 POD meeting. This meeting was ineffective and not well attended by management. There were seven vacant chairs at the center table and six vacant chairs surrounding the center table. Neither the Restart V.P. nor any of his direct reports attended the meeting. Each day of the week an agenda item is discussed. For this day material status was to be the item of discussion. This was not discussed due to poor attendance at the meeting. Procurement activities have been a critical issue for the recovery of Unit 3. The inspector routinely attends the POD meeting and has observed that no TVA senior management above the Restart V.P. have attended the meetings. The attendance at this meeting was discussed with the Restart V.P. By his direction the other managers were working on correction of other problems.

2) SWEC Weekly

On February 18, 1992, the inspector attended a field implementation 90 day lookahead schedule status meeting. This meeting was ineffective. For the second week in a row personnel commented that Bechtel was not represented. This is essentially one half of the discussion. For SWEC to plan the field work they must know when the design work is scheduled to be completed. Bechtel does the design work. The ineffectiveness of this meeting was discussed with the Restart V.P. on February 20, 1992.

3) Bechtel Weekly

On March 10, 1992, the inspector attended a weekly project status meeting held in the Athens, Alabama, Bechtel offices. This meeting was also ineffective in that the participants could not give accurate information and gave conflicting information. During the meeting, the TVA Vice-President asked a question about a schedule item that was not met and was not given a satisfactory answer. As a result of this ineffective meeting, the TVA Vice-President canceled the March 10, 1992, SWEC 90 day look ahead meeting because it would have been a meaningless activity.

4) Restart Review Board

The inspector attended, reviewed and observed the activities of the Unit 3 RRB. The items discussed included Unit 2

DCN/ECNs that would or would not be installed in Unit 3. The inspector had been previously informed by the licensee that the restart criteria for Unit 3 would be the same as Unit 2. The inspector noted that NUREG-1232, Vol. 3, Supp. 2, Safety Evaluation Report on Tennessee Valley Authority: Browns Ferry Nuclear Performance Plan, Browns Ferry Unit 2 Restart, stated:

> In addition to its corporate plan, TVA prepared separate plans to address site-specific problems at each of its nuclear plants. Volume 3 of NUREG-1232 and its supplements constitute a compilation of NRC safety evaluation reports regarding the corrective actions planned and implemented by TVA in accordance with the BFNPP, Volume 3, Rev. 2, tailored specifically for restart of Unit 2. In many cases, long-term corrective action plans extending beyond restart of Unit 2 were required to fully resolve the issues identified in the staff's letter. TVA's BFNPP described these plans in great detail.

In addition to this statement, Appendix E, Browns Ferry Nuclear Plant Commitments, of NUREG-1232 also stated:

> Any additions to the restart commitments listed in Attachments IV-1, IV-2, and IV-3 that occurred as a result of implementing the corrective action plans of the BFNPP and CNPP were reviewed by a TVA Restart Review Board in accordance with the restart criteria, see BFNPP, Table IV-1, "Restart Requirement Criteria," which have been approved by the NRC. TVA plans to continue using the restart criteria until fuel load of Unit 2, after which it will utilize a more conventional priority scheme based upon operability requirements. As part of its Operational Readiness Program, the licensee has developed a restart commitment closure process, which is being monitored and evaluated by the staff through inspections.

As a result of the observations and reviews of the Unit 3 RRB meetings, the inspector concluded there appears to be no clear cut understanding of what same criteria means in relationship to the Unit 3 restart. The inspector could not determine what process is in place to ensure that the same restart criteria is used for Unit 3 that was used for Unit 2. This item is identified as IFI 259, 260, 296/92-05-04, Activities of the Unit 3 Restart Review Board and Unit 2/3 Restart Criteria.

The inspector was informed by licensee representatives that what was observed was not an RRB. The inspector noted that the checklist definitely stated Unit 3 Restart Checklist and had a signature line titled, Approved by Restart Review Board Chairman.

c. Schedule Status

The Unit 3 Level II schedule was supposed to be updated March 7, 1992 to factor in the walkdown data. However, due to numerous walkdown activities still in progress, the schedule update is expected one month later. The electrical walkdowns were to be completed at the end of February. Safe shutdown cables, deferred

Unit 2 EQ, blacksnake, and Bechtel RFI walkdowns continue.

9. Health Physics

An inspector monitored activities at the control station for entry/exit from the RCA. The inspector observed licensee personnel performing self monitoring activities, signon/signoff of the computerized RWP system, access control procedures, control of hand carried tools and other equipment, and survey of various articles prior to exiting the RCA. The inspector did not observe any poor practices or identify any problems during this review of the licensee's program.

10. Reportable Occurrences (92700)

The LERs listed below were reviewed to determine if the information provided met NRC requirements. The determinations included the verification of compliance with TS and regulatory requirements, and addressed the adequacy of the event description, the corrective actions taken, the existence of potential generic problems, compliance with reporting requirements, and the relative safety significance of each event. Additional in-plant reviews and discussions with plant personnel, as appropriate, were conducted.

a. (CLOSED) LER 260/91-17, Failed Soldered Connection on Air Supply Line to Steam Packing Exhauster Bypass Flow Control Valve Resulted in Engineered Safety Actuation.

The reactor trip associated with this event was reviewed and closed in IR 91-43. In response to INPO SER 91-006 and the reactor trip, a control air inspection was conducted between August 13 - December 1, 1991. The results of the inspector are as follows:

Joint Type	# Inspected	# Leaking	% Leaking
Soldered	12,575	139	1.1
Mechanical	19,885	1087	5.5

Of the 139 leaking soldered joints, 2 were determined to be significant and capable of impacting plant operation. These two joints were repaired. None of the mechanical joints were determined to be significant. The inspector reviewed the control air report in the licensee's closure package.

The inspector questioned the licensee if any vibration problems were experienced on this valve because during maintenance the valve disc found was installed backwards. This problem was discussed with the system engineer. No vibration problems resulted from the valve disc installation. These actions resolve the LER.

b. (CLOSED) LER 260/91-018 Failure to Open Generator Exciter Field Breaker After Manual Turbine Trip Resulted in a Reactor Scram Required by Technical Specifications.

This LER reported to the NRC an event that occurred on October 18, 1992, where during a controlled shutdown the Unit 2 Reactor was manually scrammed from low power due to unexpected equipment responses. This event resulted in issuance by the NRC of a violation for failure to follow procedure, 259, 260, 296/91-40-01. Since the circumstances associated with this event will be reviewed as part of the followup to that violation and the

respective Scram Trip Report this item is closed.

11. Management Changes

The licensee announced on March 2, 1992, that Dan Nauman, Senior Vice President of Nuclear Power, resigned to pursue other interests.

Mr. Kingsley, in addition to his current responsibilities as President of the Generating Group, will provide direct oversight of Nuclear Power activities, and will serve as the senior nuclear officer. The following individuals will report directly to him:

Joe Bynum, Vice President, Nuclear Operations

Dwight Nunn, Vice President, Nuclear Projects

Mark Medford, Vice President, Nuclear Assurance, Licensing and Fuels

Dick Wilson, Vice President, New Generation and Quality

This interim structure will remain in place until a decision is made on the Senior Vice President position.

The licensee announced on March 12, 1992, two promotions at the Browns Ferry site.

Jon R. Rupert from Engineering Manager to Engineering and Modifications Manager

James E. Maddox from Manager of Operation Support Group to Engineering Manger.

12. Exit Interview (30703)

The inspection scope and findings were summarized on March 13, 1992 with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
259, 260, 296/92-05-01	IFI, Activities of the Unit 3 Restart Review Board and Unit 2/3 Restart Criteria.

Licensee management was informed that 2 LERs were closed.

13. Acronyms and Initialisms

AOI	Abnormal Operating Instruction
APRM	Average Power Range Monitor
ARP	Annunciator Response Procedure
ATU	Analog Trip Units
BFNPP	Browns Ferry Nuclear Performance Plan
CBHZ	Control Building Habitability Zone
CFM	Cubic Feet Per Minute
CFR	Code of Federal Regulations
CRDR	Control Room Design Review
CREV	Control Room Emergency Ventilation

DCN	Design Change Notice
DG	Diesel Generator
ECN	Engineering Change Notice
EQ	Environmental Qualification
ESF	Engineered Safety Feature
FT	Functional Test
GOI	General Operating Instruction
IFI	Inspector Followup Item
INPO	Institute of Nuclear Power Operation
IRM	Intermediate Range Monitor
IR	Inspection Report
LCO	Limiting Condition for Operation
lER	Licensee Event Report
LPCI	Low Pressure Coolant Injection
MG	Motor Generator
MOV	Motor Operated Valve
MR	Maintenance Request
MSIV	Main Steam Isolation Valve
NE	Nuclear Engineering
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSRB	Nuclear Safety Review Board
NUMARC	Nuclear Management and Resource Council
PCIS	Primary Containment Isolation System
POD	Plan of Day
PSIG	Pounds Per Square Inch Gauge
PS	Pressure Switch
QA	Quality Assurance
QC	Quality Control
RBM	Rod Block Monitor
RCA	Radiological Controlled Area
REM	Roentgen Equivalent Man
RFI	Request For Information
RHR	Residual Heat Removal
RPS	Reactor Protection System
RRB	Restart Review Board
RWP	Radiological Work Permit
SBLC	Standby Liquid Control
SD	Shutdown
SER	Safety Evaluation Report
SI	Surveillance Instruction
SSP	Site Standard Practice
SWEC	Stone & Webster Engineering Corporation
TS	Technical Specification
TVA	Tennessee Valley Authority
WO	Work Order
WR	Work Request