UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
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ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-259/94-01, 50-260/94-01, and 50-296/94-01

Licensee: Tennessee Valley Authority
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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: January 15 - February 18, 1994

Inspector: C. A. Patterson, Senior Resident Inspector — 03/14/94 Date Signed

Accompanied by: J. Munday, Resident Inspector
R. Musser, Resident Inspector
G. Schnebli, Resident Inspector

Approved by: Paul J. Kellogg, Chief, Reactor Projects, Section 4A, Division of Reactor Projects — 3/14/94 Date Signed

SUMMARY

Scope:

This routine resident inspection included surveillance observation, maintenance observation, operational safety verification, modifications, Unit 3 restart activities, fire protection, self assessment, and action on previous inspection findings.

One hour of backshift coverage was routinely worked during the work week. Deep backshift inspections were conducted on January 20, 21, 23, and February 2, 12, 13, 1994.

Results:

In the area of surveillance, a violation was identified by an NRC inspector during the review of a completed containment visual inspection surveillance, paragraph 2. Three elevations were not inspected due to refueling operations in progress. The licensee's review of the surveillance by several groups did not detect the problem. The licensee conducted an analysis for operability and initiated an incident investigation of the problem.

In the area of maintenance (modification), a violation was identified by an NRC inspector concerning the upgrade of an offsite power source in the switchyard, paragraph 5. Work plans being used did not contain the proper signatures for numerous items. The work was being performed by customer service group craft that were not trained on work plans. There was no quality control involvement with the modification and only a contractor field engineer providing supervision. The licensee stopped the job and provided training to the craft on work plans.

In the area of plant support, a violation was identified by the licensee for a missed fire watch for an inoperable carbon dioxide system, paragraph 7. A similar event occurred on June 4, 1993, when a required firewatch was relieved prior to the system being declared operable.

In the area of engineering, a violation was identified with two examples of design errors concerning Appendix R, paragraph 7. The first example was that power supply cables for both reactor water cleanup system containment isolation valves were routed in the same fire zone without adequate separation. The second example was that a fault in the power supply to a raw cooling water pump was not adequately separated to prevent propagation to a shutdown board. Both of the issues are being covered by compensatory fire watches but will require extensive plant modification during the next refueling outage to correct.

In the area of engineering/technical support, a violation with two examples was identified by an NRC inspector for failing to make the required 10 CFR 50.72 and 50.73 reports, paragraph 8. The first example was that two trains of the standby gas treatment system were inoperable and could have prevented the fulfillment of a safety function. The second example was that two Appendix R design errors resulted in the plant being outside the design basis.

In the area of surveillance, a noncited violation was identified for an inadvertent emergency equipment cooling water pump motor start during a surveillance, paragraph 2. The licensee made a 4-hour notification and initiated an incident investigation of this event. A second party check was not performed adequately to prevent the installation of jumpers on a wrong relay.

In the area of plant support, an unresolved item was identified concerning an undocumented modification to the diesel driven fire pump that prevented the automatic start function, paragraph 5. The licensee initiated an incident investigation of this event.

In the area of operations, routine control of plant evolutions such as backfilling reactor water level reference legs and response to equipment failures were good. These evolutions are conducted in a controlled cautious manner. Upgrades to focus on operable and common equipment in the Unit 1 control area was good.

In the area of radiological controls, a weakness was noted in the implementation of the use of digital alarming dosimeters, paragraph 4. Personnel were not familiar with how to properly wear the dosimeters or the purpose of the alarm.

REPORT DETAILS

1. Persons Contacted

Licensee Employees:

O. Zeringue, Senior Vice President, Nuclear Operations
*R. Machon, Plant Manager
J. Rupert, Engineering and Modifications Manager
T. Shriver, Licensing and Quality Assurance Manager
D. Nye, Recovery Manager
E. Preston, Operations Manager
*J. Maddox, Engineering Manager
*M. Bajestani, Technical Support Manager
*A. Sorrell, Chemistry and Radiological Controls Manager
*C. Crane, Maintenance Manager
P. Salas, Licensing Manager
*R. Wells, Compliance Manager
*J. Corey, Radiological Control Manager
J. Brazell, 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
*J. Munday, Resident Inspector
*R. Musser, Resident Inspector
G. Schnebli, 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. RCIC Turbine Exhaust Rupture Disc High Pressure Calibration

On February 1, 1994, the inspector witnessed the performance of portions of 2-SI-4.2.B-34(A) and 2-SI-4.2.B-34(C), Reactor Core Isolation Cooling System Turbine Exhaust Rupture Disc High Pressure Calibration for the 2-PS-71-11A and 2-PS-71-11C, respectively. These switches sense pressure in the rupture disc volume and isolate the RCIC steam supply valves on increased pressure. This surveillance verifies the switches are in calibration and satisfies the requirements of TS Table 4.2.B. The inspector verified the test equipment being used was appropriate for the job, the procedure was the most current revision, and the instruments were removed from service, tested, and returned to service within the time allowed by the LCO. The inspector also reviewed the completed procedure and noted no discrepancies.. In addition, 2-SI-4.2.B-40A, RCIC System Logic Functional Test, was reviewed by the inspector to verify that all components of the turbine exhaust rupture disc pressure high isolation logic were being tested. While performing this review the inspector noted errors on RCIC logic drawings 2-45E626-1 and 2-45E626-2. These discrepancies were of minor significance but were brought to the attention of the system engineer for his review and validation. The system engineer initiated PDD 94-055 to correct the errors. No other discrepancies were noted.

b. Inadvertent Start of EECW Pump

On February 4, 1994, during the performance of 0-SI-4.2.B-67, RHR Service Water Initiation Logic, A3 EECW pump inadvertently started. During this portion of the SI jumpers are installed to prevent automatic starting of RHRSW pumps on simulated low RCW system pressure. The jumpers should have been placed on relay SSCRA but were installed on a relay labeled SPARE. The inspector reviewed the SI procedure and the procedure step was required to be second party checked. The inspector toured the 4kV Shutdown Board 3EA in the DG building where the relays are located. The two relays are clearly marked with an identification label underneath each relay on the front of the panel. The jumpers are placed on the back of the panel. The SSCRA relay is located directly above the SPARE relay.

The licensee made a 4-hour notification per 10 CFR 50.72, and Incident Investigation II-B-94-05 was initiated for the event. Since there have been no similar violations during the past two years, this violation of procedural compliance meets the criteria for a licensee identified violation. It will be identified as NCV 259, 260, 296/94-01-01, Inadequate Second Party Check. This violation will not be subject to enforcement action because the

licensee's efforts in identifying and correcting the violation met the criteria specified in Section VII.B of the Enforcement Policy.

c. Containment Coatings

During the first quarter of 1991, TVA's Nuclear Quality Audit and Evaluation Department performed an audit of Service Level I Protective Coating Programs for all TVA nuclear plants. This inspection effort reviews the results of the audit and corrective actions as they relate to the Browns Ferry Nuclear Plant. Two findings were identified by the audit team at Browns Ferry.

The first and more significant issue dealt with the failure to identify the addition of uncontrolled coatings into the Unit 2 containment for evaluation and possible inclusion in the uncontrolled coatings log. Additionally, nuclear engineering had failed to identify all uncontrolled coatings in the log during initial baseline walkdowns. As a result of these findings, the licensee reperformed a baseline evaluation of the containment to identify all uncontrolled coatings. This effort resulted in the issuance of a revised containment coating log. Numerous items were identified with uncontrolled coatings with thicknesses greater than 3 mils. The majority of the items identified with coatings greater than 3 mils were sanded and feathered down to a dry film thickness of less than or equal to 3 mils. This work was performed in accordance with work order 91-27917-00. Items with uncontrolled coatings of 3 mils or less were accepted as is based on Detroit Edison Report No. DECO-12-2191, Revision 4 (June 1985), "Enrico Fermi Atomic Power Plant Unit No. 2 - Evaluation of Containment Coatings." This report concludes that coatings with a dry film thickness of 3 mils or less are too thin to form debris that might contribute to strainer blockage. This position has been accepted by the NRC.

The inspector reviewed the updated unqualified containment coatings log which is documented under Quality Information Request/Release QIRMTBBFN88025, Rev. 4. This document also provides the unqualified containment coatings evaluation. All unqualified containment coatings, including those with a dry film thickness of less than 3 mils, are included in the log. The total allowable unqualified coatings (with a dry film thickness of greater than 3 mils) is 157 square feet. This amount of coating, which might flake off during an accident, would not block ECCS pump strainers enough to affect the net positive suction head requirements of the RHR and core spray pumps. Currently, Browns Ferry's uncontrolled containment coating log lists approximately 78 square feet of coating with a dry film thickness of greater than 3 mils. This amount is well within the 157 square foot limit.

Additional corrective actions for this matter involved revising MAI-5.3, (a Modification and Addition Work Instruction Procedure), Protective Coatings, to control all Service Level I protective coatings at the site. All personnel associated with writing and planning of work plans (modifications) and work orders (maintenance) were informed of the requirements of MAI-5.3. Additionally, a special work step was inserted into the work plan logic in (SSP-9.3, Plant Modifications and Design Change Control,) to require all material being installed inside primary containment to be coated with Level I coatings or evaluated per MAI-5.3. Likewise, SSP-6.2, Maintenance Management System, was revised to require that all painted material being installed inside primary containment be evaluated per MAI-5.3. These actions were reviewed by the inspector and found to be acceptable.

The second issue identified by the audit team dealt with protective coating failures in the Unit 2 drywell. Numerous areas of lack of adhesion and delamination of coatings were noted on various elevations and azimuth locations within the drywell. These items were dispositioned in accordance with WO 90-08921-00 by removing the coatings not properly adhering to the base surfaces. Procedure MAI-5.3, Protective Coatings, and TS 4.7.A.2.K, requires that the drywell surfaces be inspected each 18 months for structural integrity and condition of coatings. This inspection provides adequate measures to ensure containment coatings remain in an acceptable condition.

On January 27, 1994, as a part of this inspection effort, the inspector reviewed completed surveillance records for 0-SI-4.7.A.-2.K, Primary Containment Drywell Surface Visual Inspection, which was performed during the Unit 2 Cycle 6 refueling outage. The SI was performed April 28, 1993. The review indicated that visual inspections required by steps 7.6.2, 7.6.3, and 7.6.4 were not completed for the upper three elevations (604', 616', and 633') in the Unit 2 drywell. These inspections involved visually verifying that no structural damage, displacement, or deterioration existed in relation to piping connectors, supports, penetrations, structural supports, platform steel, duct hangers, concrete walls, the steel liner, and the cable trays. The data sheet associated with the inspection indicated that only the lower three elevations (550', 563', and 584') were inspected due to ongoing fuel loading. The inspector brought this matter to the attention of the licensee. The licensee promptly reviewed the matter for operability and potential non-conformance to technical specifications. The licensee determined that sufficient evidence existed to reasonably conclude that the surveillance criteria were met or would have been met based on other inspections performed. These inspections include the ASME Section XI Inservice Hydrostatic Test and the Drywell Closeout inspection performed in accordance with 2-SI-3.3 and 2-GOI-200-2 respectively. The inspector reviewed the licensee's analysis and concluded no immediate safety concern existed.

The failure to fully complete SI 0-SI-4.7.A.2.K, is a violation of TS 4.7.A.2.K. The significance of this matter is further compounded by the fact that the results (data) for the test in

question were reviewed by a senior reactor operator, mechanical maintenance supervisor, and cognizant system engineer without the deficiency being discovered. The licensee is currently conducting an incident investigation on this situation. This matter will be tracked as VIO 260/94-01-02, Failure to Properly Perform Containment Visual Inspection Surveillance.

Two violations 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 documents 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. Diesel Generator 1D Maintenance

On January 18, 1994, the inspector witnessed portions of an inspection of the 1D DG cylinder liners. The inspection was being conducted in response to a Part 10CFR21-0067 report which identified a cracking problem with two particular models of cylinder liners on EMD DGs. Browns Ferry has the model DG referred to in the report, however, this inspection determined that they do not have the model cylinder liners identified as defective. The inspector witnessed the inspection, conducted in accordance with WO 94-00459-03, and noted no concerns. On January 25, 1994, the 3D DG was inspected and on February 7, 1994, the 3A DG was inspected with neither having the model liner identified. An inspection of the remaining DGs cylinder liners will be conducted as they are removed from service for scheduled routine maintenance.

b. Reactor Water Level Instrument Backfill

On January 25, 1994, the inspector observed maintenance personnel backfill the A side reactor water level instrument reference leg. Prior to the backfill the A side instruments indicated two to three inches higher than the B side instruments. Following the maintenance the B side instruments indicated approximately two inches higher than the A side. The craft performed the work using WO 93-14451-00. The inspector verified the proper authorizations

were obtained, M&TE was appropriate, and the WO was being followed as written. No discrepancies were noted.

On January 26, 1994, the licensee determined that the B side level instrument reference leg also needed backfilling. Prior to performing the work the B side instruments indicated approximately two inches higher than the A side instruments. After the maintenance the B side instruments indicated approximately one inch lower than the A side instruments, which satisfies the acceptance criteria of site procedures. Engineering and Operations were satisfied with these results. The inspector reviewed the controlling WO 93-15059-00 and noted no discrepancies.

On February 14, 1994, the A side reactor water level instrument reference leg was again backfilled. Before the backfill, the A side instruments indicated approximately three inches higher than the B instruments. Following the backfill, the A side instruments indicated approximately one inch higher than the B instruments. While slight leaks from three water level instruments were identified as contributing to the problem, the system engineer stated that backfilling will probably be required approximately every 45 days. The inspector witnessed the process and found no discrepancies.

On February 17, 1994, the wide range 'A' reactor water level instrument reference leg was backfilled. The work was performed in accordance with WO 94-00037-01, which contained step by step instructions detailing the evolution. The licensee determined that in order for the work to be performed on line and in a safe manner, three TS instruments would have to be removed from service and appropriate LCOs entered. A pre-job briefing was conducted by the system engineer to ensure that all involved personnel knew their individual responsibilities as well as the entire "backfill team."

Prior to the backfill, the 'A' side instrumentation indicated water level exceeded the 'B' side instrumentation by approximately four inches. The inspectors observed the evolution from both the control room and in the field. The work was performed in accordance with procedures and progressed in a timely and safe manner. Following the backfill, the 'A' and 'B' instruments indicated approximately within one inch of each other. No discrepancies were identified.

Previous discussion of backfilling and the modification for resolution of these problems by NRC Bulletin 93-03 is discussed in IR 93-39.

c. ECCS Inverter Failure

On February 14, 1994, the Division II ECCS ATU Inverter failed as a result of a blown fuse. The inverter supplied power to the ATUs which provide auto start functions for safety related systems. The loss of this inverter placed the plant in an LCO requiring the unit to be in Hot Standby in six hours and Cold Shutdown in the following thirty hours unless corrective measures are taken sooner. Approximately two hours into the event the fuse was replaced, however, it was then identified that an electronic card which controls the inverter output frequency was also defective. The card was replaced and the system satisfactorily returned to service approximately one hour later. The LCO was exited without a plant shutdown commencing. A one hour report to the NRC was made, in accordance with 10 CFR 50.72, to report the inoperability of the HPCI system and to give the general status of the plant. The licensee will followup with a thirty day report. The licensee intends to send the fuse and electronic card to the vendor for analysis in an effort to determine the cause of the failure. The inspector observed the troubleshooting, maintenance, and post maintenance test activities and noted no discrepancies.

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. Unit Status

Unit 2 operated continually without any significant problem during this period. At the end of the period the unit had been online for 260 days. Minor water level indication variations occurred discussed in this report.

b. Control Room Operations

During routine tours of the control room the inspector noticed several improvements to the Unit 1 control room. Although there are no plans to return the unit to operation, some common and other equipment can be operated from the control boards. The number of hold order tags has greatly been reduced as the system status on some systems are no longer controlled. The new type pump motor hand switch handles were put on for the RHRSW pumps. Chart recorders that are no longer in use have a sign placed over the recorder stating the equipment is out of service. Other enhancements were made to upgrade the appearance of Unit 1 control room and focus operator attention on the remaining operable and common equipment.

c. Control Bay Tour

During a routine tour of the control building and electrical board room containing 4160 volt shutdown board C on February 8, 1994, the inspector identified the following concerns:

1.) A circuit breaker for compartment 8A on 480 volt board 2A was in the off position and did not have an identification label similar to the other breakers. This was reviewed and determined to be a spare breaker compartment. The licensee put a note in the plant night orders for operators to be more aware of labeling problems.

2.) Next to the control room abandonment procedure storage cabinet, with a locking tab in place, was a controlled copy of the procedure, 2-AOI-100-2 dated October 19, 1993, revision 21, in another green storage cabinet. The inspector determined that the latest revision of the procedure was revision 24 dated December 15, 1993. The storage cabinet with the locking tab was opened and the correct copy of the procedure was in place. The licensee removed the copy with the out of date revision. The inspector discussed with the licensee that old copies should be shredded, torn in half, or identified by some other means to insure they are not used.

3.) WR C160866 tag dated December 3, 1993, was to fill in or seal a partial penetration for an opening in the floor. The licensee removed this seal and determined it was being

monitored by a compensatory fire watch. Words were added to the tag to identify the action.

4.) A fire alarm had sounded around 7:00 a.m. and the fire truck responded, however, there was no log entry in the ASOS or SOS control room logs. SSP-12.1, Conduct of Operations, under section 3.11.3, Information to be Recorded, lists medical/fire emergencies as items to be recorded. Operations management reviewed this and determined that an entry was made in the Unit 1 operators log and a late entry was added to the SOS log. The event occurred around shift turnover time and the log entry was overlooked.

d. Housekeeping

On January 24, 1994, during a routine tour of the cable spreading room the inspector noticed a decline in housekeeping standards. The inspector entered the Unit 1 and 2 room through door 533 and noticed the following next to the entrance door:

Sign for phone fallen to the floor
Caution sign for CO2 fallen to the floor
A padlock locked around a cable in a cable tray
Broken glass on the floor
Conduit fittings under a ventilation duct
General area dusty
Graffiti on exit security card reader

These findings were discussed with plant management. After the concerns were again raised on February 4, 1994, items were promptly corrected.

e. REX System Problems

In IR 93-39 the inspector discussed problems with reliability of the REX system. The licensee compared the TLD dose for the fourth quarter to the Merlin Gerin (MG) digital alarming dosimeters (DADs). The MG dose was 20% lower than TLDs. The licensee initiated a radiological awareness report, 94-006, to address the issue. Additionally, on February 1, 1994, a site bulletin was issued alerting personnel that a possible contributor for the disagreement was in the way the MG dosimeter was worn. It will only report 75% of the dose if the face of the device is toward the body.

Also, the inspector identified that DADs would beep while wearing them but display no exposure. This was discussed with radiological controls manager. Apparently some DADs were set to beep at 0.1 mr/hr instead of 1 mr/hr. There was general confusion among technicians and plant workers as to the purpose of the beeps. These issues are further discussed in health physics inspection report 94-05

f. Secondary Containment Interlocks

As previously discussed in IR 50-259,260,296/93-45, a problem had been noted with the operation of the secondary containment interlocks between the Unit 1/2 reactor buildings and the turbine building which resulted in monentary violations of secondary containment. In response to this matter, the licensee initiated a design change to modify the interlocks. During the inspection period, work commenced in accordance with DCN W13294 to modify the Unit 1/2 reactor building to turbine building interlocks. Current plans are that these new interlocks will be operational on March 15. The work on the Unit 3 reactor building to turbine building interlocks is schedule to commence on March 15 and complete on April 21. The inspectors will continue to monitor the licensees progress in this area.

No violations or deviations were identified in the Operational Safety Verification area.

5. Modifications (37700, 37828)

The inspectors maintained cognizance of modification activities. This included reviews of scheduling and work control, routine meetings, and observations of field activities. Throughout the observation of modifications being performed in the field QC inspectors were observed monitoring and documented verification at work activities.

On February 3, 1994, the inspector observed modification activities associated with the capacitor bank. This modification will correct the existing relaying scheme which does not meet TVA standards, remove compacitors that contain PCB's, and will increase the MVAR capacity needed to support plant voltage during an accident when offsite power is supplied from the 161 kv system. Work Plans WP0762-93 and 0765-93 were reviewed with the following discrepancies noted:

a. WP 0762-93
   - The clearance number had not been entered and documented as established.
   - Housekeeping inspections were not documented as having been performed since January 1, 1994.

b. WP0765-93
   - Modifications and SSS/Unit ASOS authorizations had not been obtained prior to commencing work.
   - Pre-job briefings were not documented as having been performed.
   - Work control group notification prior to commencement of work was not documented as having been performed.

- The clearance number had not been entered and documented as established.

- M&TE ID numbers were entered without work being performed, four examples.

- Wire terminations were made with M&TE but the M&TE IDs were not documented, two examples.

- Cable meggering completed but not signed by the craft performing the work. After it was identified by the inspector, the craft signed and backdated each step with the dates it was performed.

These discrepancies were brought to the attention of licensee management whereupon all capacitor bank modification work was stopped. Discussions with the craft performing the modification indicated that they did not understand the work plan process and their responsibilities associated with completing that process. It was determined that this type of training was never afforded these individuals. The licensee provided this training to the craft personnel and following its successful completion allowed the work to restart.

In addition, the inspector noted that neither TVA nor QC provided any direct supervision or quality control measures for this modification. A SWEC field engineer was responsible for coordination of the work activities. Although the modification has been ongoing for approximatley 3 months, these problems had only recently been identified by the SWEC engineer but had not yet been brought to the attention of licensee management.

SSP 6.1, Conduct Of Maintenance, Step 3.4.1, states that all personnel shall be indoctrinated in the importance of procedural compliance and what steps should be taken if the task cannot be performed by the procedure as written. Failure to obtain the required signatures and data as required by the work plans is a violation of this requirement and will be tracked as VIO 259, 260, 296/94-01-03, Failure To Follow Procedure on Capacitor Bank Modifications.

One violation was identified in the modifications area.

6. Unit 3 Restart Activities (30702, 37828, 61726, 62703, 71707)

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.

During this inspection period the resident inspectors commenced holding weekly meetings with licensee management responsible for the Unit 3 restart effort. The meetings were instituted to keep the resident inspectors informed of the current Unit 3 status in regards to schedule adherence and major work accomplished.

a. System SPOC's

The purpose of SPOC process is to provide a systematic method for evaluating items and issues which potentially affect the ability of Unit 3 systems and Unit 3 portion of common systems to perform as designed. This process determines the status of each item/issue and assures completion of those which affect system return to operation for Unit 3 restart. For each system evaluated, the SPOC process may be accomplished in two phases. Phase I SPOC addresses the Restart Test Program testing milestone if that milestone exists for the system, and establishes system status control by the Operations department. Phase II SPOC addresses System Return to Operation in preparation for the declaration of system operability. Each phase ensures that open items/issues which potentially affect the phase are either completed, or reviewed and satisfactorily dispositioned. The SPOC process does not declare system operability. Rather, it is used to support a declaration of system operability which is made after other requirements for operability are satisfied (e.g., support systems available, performance of Surveillance Instructions, etc.).

System 027, Condenser Circulating Water System

During the initial startup of 3C CCW pump on November 18, 1993, smoke was observed issuing from the packing stuffing box of the pump and pump vibration was increasing noticeably. The licensee secured the pump and commenced troubleshooting activities which included the following:

1.) The bearing lube water line to the stuffing box and upper bearing was observed to be at an elevated temperature indicating a lack of lube water flow. Lube water flow was verified available to the pump by installed plant instrumentation.

2.) The lube water supply line to the upper bearing and stuffing box was disconnected and no water flow was present. However, a solid stream of water could be seen flowing through the supply piping to the lower bearings.

3.) The vendor, Ingersoll-Dresser Pumps, was contacted to provide additional guidance as they had just refurbished the pumps during this outage.

4.) Bearing lube water flow was elevated to the maximum rate available to each pump and no back pressure was obtained from the lower bearings to force lube water flow to the upper bearing and stuffing box. Divers were brought in and they inspected the lube water piping below the pump deck. No leakage or abnormal conditions were identified.

5.) At the vendors recommendation, 3/4 inch orifices were installed in the lube water supply line just below the tee of the branch line supplying lube water to the upper bearing and stuffing box. This effort was to provide a flow restriction to the lower bearings which would cause flow to the upper bearing and stuffing box. However, the orifices did not provide adequate flow to the pumps at recommended flow rates and only marginal flow at the maximum supply flow rate available.

6.) The orifices were removed and further discussions were held with the vendor. The 3C pump was inspected using a borescope to determine if any components could have been omitted during the rebuild. No deficiencies were found.

7.) At the vendors recommendation orifices were installed in the lower two lube water lines to the lower bearings on the 3B and 3C pumps. This effort was to provide sufficient backpressure in the supply line to force lube water flow to the upper bearing and stuffing box.

8.) Testing after the orifices were installed showed that flow rates to the upper bearing and stuffing box area were acceptable on the 3B and 3C CCW pumps.

Based on the successful testing of the 3B and 3C CCW pump, subsequent to the modification of the two lower lube water supply lines, the licensee will also modify the 3A pump. The inspectors will continue to monitor this issue during the Unit 3 testing phase.

b. Scaffold Program

The inspectors reviewed the licensee's scaffold program which included procedures, training, inspections, and records/documentation. The procedure that governs the installation and maintenance of scaffolding is 0-TI-264, Scaffolds and Temporary Platforms, Revision 4, dated January 29, 1993. This procedure was reviewed in-depth and the inspectors considered it a comprehensive instruction that ensured scaffolding was erected in a reliable and safe manner and took into account safety-related functions of plant equipment. The inspectors also reviewed the maintenance training program and training attendance records for scaffolding, MTS 151, Scaffold Erection, which covered the requirements of 0-TI-264.

Scaffolding and platforms installed in Unit 3 Turbine and Reactor buildings were walked down by the inspectors and found to meet the requirements of 0-TI-264. The scaffold was constructed securely and the appropriate tags were installed. The scaffold permit tag and log provides an up-to-date record of scaffolding installed in the plant. This tag also maintains a record of inspections conducted on scaffolding which will remain erected for an extended period of time. Step 7.11.14 of 0-TI-264 requires the responsible foreman/supervisor or their designee to inspect scaffolding in use every 48 hours and document the inspection on the back of the scaffold permit tag. While the inspectors were in the Unit 3 reactor building they observed this inspection in progress. When questioned, the person conducting the inspection was knowledgeable of the procedure and the requirements of the inspection. In addition, scaffolding located in noncontaminated portions of the RCA are required to be surveyed by RADCON prior to use and at least every seven days thereafter. This is documented on a survey update tag which is also attached to the scaffold. This tag was also verified to be in place, where required, by the inspectors.

0-TI-264 requires that users of scaffolding visually inspect scaffold prior to use to ensure the scaffold is safe and has had the appropriate inspections/surveys performed in the required time frame. Abnormal or defective conditions are to be reported to the erecting foreman or RADCON, as required, for any necessary corrections or surveys.

In conclusion, the inspectors considered the licensee's scaffold program to be comprehensive.

c. Unit Separation

1.) Breaker Found In Off Position

During a routine tour on January 24, 1994, the inspector identified that an electrical circuit breaker, labeled as required to support Unit 2 operation, was in the open position. The breaker was for reactor building lighting cabinet LD-3 (compartment 1A) on 250 VDC reactor MOVBd 3B. Circuit breakers such as this are identified by a sign as required SSP-12.50, Unit Separation For Recovery Activities. This was discussed with the Unit 3 operator. Recent clearances were reviewed and no reason was found for the breaker to be opened and it was closed.

2.) Personnel Access

The inspector noticed that a gate separating Unit 2 operating space and Unit 3 in the turbine building was removed and contractor personnel with light blue hardhats were moving freely in and out of Unit 2. This was discussed

with licensee management. The inspector will continue to monitor these activities as part of the routine activities.

7. Fire Protection

a. Missed FPP Required Firewatch

On January 20, 1994, the licensee identified that a Fire Protection Impairment Permit (Att. F) for the Unit 1/2 DG CO2 system, was closed out and the required compensatory measure removed before the system was returned to operable status. Modification, DCN F26949A, was being performed on the fire detectors in the DG building and the CO2 suppression system protecting this area was valved out and placed under clearance to prevent inadvertent actuation. A firewatch was established as required, however, on January 19, 1994, at 1400 hours, upon completion of the field work, the firewatch was released. On January 20, 1994, at 0015 hours, it was identified that the CO2 storage tank had not been unisolated and returned to service. The FPP, section 9.3.11.D.2, requires that a firewatch be established within one hour when the Unit 1/2 DG CO2 suppression system is removed from service. Failure to maintain a firewatch with the CO2 system removed from service is a violation of these requirements and is identified as VIO 259, 260, 296/94-01-04, Missed FPP Required Firewatch. A similar event occurred on June 4, 1993, when a required firewatch for the Unit 3 DG CO2 suppression system was relieved prior to the system being made operable and was identified as IFI 296/93-23-04, Missed Appendix R Firewatch, and will be closed by this report. Corrective Action for both events will be established and tracked by this violation.

In addition, the licensee identified during its review of this event that although this DCN had affected primary drawings, a review by the system engineer had not been performed. This is a requirement of the licensees DCN program. The licensee initiated BFPER940022 to track this event and to determine corrective action to prevent recurrence.

b. Diesel Driven Fire Pump

On January 25, 1994, the DDFP failed to auto start during the performance of 0-SI-4.11.B.1.f, Simulated Automatic And Manual Actuation Of The High Pressure Fire Pump System. It was determined that an engine lock-out relay was preventing the auto start. The local control panel had been replaced in October, 1993, per DCN V24443A with what was identified as an identical replacement. However, following failure of the auto start it was determined that the lock-out function had been defeated on the old panel without the drawings being updated. WR C191069 was generated to make the appropriate physical changes to disable the lock-out function on the new panel and DCN T28513A was written to

revise the drawings. BFPER940020 was written to determine the root cause of the event, including why the failure of the auto start feature was not detected during the PMT for DCN V24443A. This item will be identified as URI 259, 260, 296/94-01-05, Diesel Fire Pump Auto Start Failure, pending completion of this PER.

c. Appendix R Safe Shutdown Concerns with 1D Raw Cooling Pump

On December 29, 1993, the licensee determined that a fault on cables associated with the 1D RCW pump could prevent the safe shutdown of Unit 2 following an Appendix R event. The 1D RCW pump is not required to achieve safe shutdown in the event of an Appendix R fire, however, it is powered from 4KV SDBD A which also supplies power to components that are required during an Appendix R event. If a fault were to occur on one of the cables associated with this pump, it could propagate to equipment required to achieve safe shutdown or prevent Appendix R equipment from starting. The licensee established the appropriate compensatory measures and initiated BFPER930183 to resolve the issue. This condition is a violation of 10 CFR 50 Appendix R, Criterion III, which requires cables that could prevent operation or cause maloperation of systems necessary to achieve and maintain hot shutdown be protected by appropriate fire barriers or by adequate separation. This item is identified as example one of VIO 260/94-01-06, Appendix R Design Errors.

d. RWCU Isolation Valves Cable Separation Pump

From the discussion in paragraph 9.c., an Appendix R design error was made concerning the separation of cables for the RWCU containment isolation valves. This is identified as the second example of violation 260/94-01-06, Appendix R Design Errors.

8. Self Assessment (40500)

a. PORC Meeting

On February 3, 1994, the inspector attended a PORC meeting. Items discussed included revisions to SSP-12.53, Tracking No. 10, 10 CFR 50.59 Evaluations of Changes, Tests, and Experiments, SSP-3.4, Tracking No. 10, Corrective Action Program, 2-EOIPM TOC Tracking No. 12, EOI Program Manual Table of Contents, and 0-TI-313, Engineering Evaluations for Operability Determination. All items reviewed were approved after making additional minor changes. The PORC members in attendance satisfied the requirements of TS 6.5.1 and SSP-12-10. No discrepancies were noted by the inspector.

b. Shutdown Risk Assessment

On January, 14, 1994, the inspector attended a portion of the licensee's meeting to discuss shutdown risk associated with a forced outage maintenance schedule. Representatives from

Operations, Nuclear Engineering, Technical Support, Operations Scheduling, and Maintenance were in attendance. The group reviewed a schedule covering the shutdown from 100 percent power to cold shutdown and then back up to 100 percent power. The schedule was broken down into segments with each segment being examined for any activities that might negatively impact the operation of the plant. The review identified several maintenance items that were rescheduled, such as, postponing as much work as possible in radiation areas until after the plant is shutdown to reduce the amount of radiation dose received. Another item was rescheduled because it would require maintenance activity in the control room during power maneuvers. The inspector thought the meeting was productive and could result in a decrease in shutdown risk.

c. Failure to Make Required 10 CFR 50.72 and 50.73 Notifications

1.) <u>Standby Gas Treatment System Inoperability</u>

On January 4, 1994, at 6:34 a.m., with Unit 2 operating at 100 percent power, the 1/2 'A' DG was declared inoperable due to a fuel oil leak at the engine driven fuel oil pump. At approximately 4:15 p.m. that same day, the timing delay breaker closing relay for the 3D DG was discovered with a tripped relay target. Attempts to reset the relay were made; however, they were unsuccessful. At 7:40 p.m., the 3D DG was declared inoperable (effective at 4:15 p.m.). Because the 1/2 'A' DG is the emergency power supply for the 'A' SBGT and the 3D DG is the emergency power supply for the 'C' SBGT, TS 1.C.2 requires that both trains of SBGT be declared inoperable and the Unit be placed in at least hot standby within six hours and in at least cold shutdown within the following 30 hours. The licensee entered this LCO from 4:15 p.m. until 8:25 p.m. when the 3D DG was repaired and returned to service.

Browns Ferry was designed with a total of three SBGT trains. The design basis accident for each of the units is a LOCA concurrent with a LOSP. In order to mitigate such an accident, FSAR section 5.3.4.1 states that two trains of SBGT are required to auto-start in order to maintain secondary containment pressure ¼ inch water below atmospheric pressure. With the condition described above, and the occurrence of the design basis accident, only one train of SBGT ('B') would have auto started. 10 CFR 50.72 (b)(2)(iii)(D) requires that any event or condition that alone could have prevented the fulfillment of the safety function of a system that is needed to mitigate the consequences of an accident be reported to the NRC within four hours via the ENS. The licensee failed to make this notification as well as the followup 30 day written notification required by 10 CFR 50.73 (a)(2)(v)(D).

Reportability of this matter is further supported by NUREG-1022, (page 15, 5th paragraph) which states that for a safety system that includes three or more trains, the failure of two or more trains should be reported if, in the judgement of the licensee, the functional capability of the overall system was jeoparized. This matter is a violation of 10 CFR 50.72 and 10 CFR 50.73 and will be cited as the first example of VIO 259, 260, 296/94-01-07, Failure to Make Required Notifications.

2.) Appendix R Concerns

Paragraph 7 of this report references two instances where the licensee identified problems with proper separation of power supply cables. The first matter dealt with power supply cables to the redundant RWCU primary containment isolation valves being located within twenty feet of each other and not being adequately protected by an appropriate fire barrier. In the second instance, the power supply cables to the 1D RCW pump were not adequately separated from the safety related 4KV Shutdown Board A. These matters are being cited as violations to 10 CFR 50, Appendix R, Criterion III.G.2.

In each of these instances, the Appendix R requirements were never met resulting in a condition outside of the design basis of the plant. 10 CFR 50.72 (b)(1)(ii)(B) requires that any event or condition that results in the nuclear power plant being in a condition outside of its design basis be reported to the NRC within one hour via the ENS. Additionally, the licensee is required to report these matters in accordance with 10 CFR 50.73 (a)(2)(ii)(B). In both instances, the licensee failed to make the required telephonic and written notifications required by these parts. These matters are violations of 10 CFR 50.72 and 10 CFR 50.73 and will be cited as the second and third example of VIO 259, 260, 296/94-01-07, Failure to Make Required Notifications.

In both of these instances the licensee conducted a review of the events for reportability using NUREG 1022, but concluded the events were not reportable.

9. Action on Previous Inspection Findings (92701, 92702)

a. (CLOSED) VIO 259, 260, 296/92-29-02, Failure to Sign Out a Hold Order Prior to Performing Work

This issue occurred due to contractor problems using the clearance procedure. The licensee conducted an incident investigation II-B-92-052, concerning the problems. Additional training was conducted for personnel holding clearance authorization. This included a practical exercise, requalification examination, and was made part of the annual requalification for these people. Additionally, the licensee implemented a modification performance monitoring program that checks clearances in the field. The inspector reviewed the licensee's closure package for this item. During routine tours of the facility additional problems have not been identified in this area.

b. (CLOSED) IFI 296/93-23-04, Missed Appendix R Firewatch

On June 4, 1993, an hourly roving firewatch, required because the Unit 3 DG building CO2 system was out of service, was relieved before the CO2 system was made operable. On June 5, 1993, this was recognized and the firewatch was re-established. Problem Evaluation Report BFPER930082 was initiated to track this event. As stated in paragraph 7.a, on January 20, 1994, a similar event occured when the firewatch was relieved from monitoring the Unit 1/2 DG CO2 tank before it was made operable. Therefore, this item is being closed out. Corrective actions will be tracked by VIO 259/260-94-01-04.

c. (CLOSED) URI 260/93-39-01, Inadequate Safe Shutdown Procedure Revision

This item was that the licensee made 112 changes to the fire protection safe shutdown equipment compensatory measures. Characteristic of the changes was revising a requirement to isolate the RWCU system in four hours for inoperable containment isolation valves to permit the establishment of a fire watch after seven days. The licensee requested a meeting concerning this issue. A meeting was held on January 27, 1994, to discuss the changes. The question about RWCU isolation valves arose due to erroneous cable reporting information to perform an Appendix R analysis. Later it was determined that cables for both isolation valves were routed in the same fire zone.

From the meeting it was determined that the problem with the RWCU isolation valves was a design problem dealing with inadequate separation. Thus, section 9.3.11.6, of the fire protection plan fire-rated assemblies was applicable and required a fire watch in one hour. The problem should not have been addressed by the appendix R safe shutdown program compensatory measures table.

Furthermore, the changes made to the compensatory measures table were consistent with other compensatory measures dealing with a loss of an appendix R function or equipment. For example, removal of a DG for maintenance allows 7 days before a fire watch is required. In this case a loss of an appendix R capability would require a fire watch, but inoperable valves must be isolated in four hours.

Although some confusion existed as to the applicable table for this analysis problem, the changes made to the plan were consistent with other changes previously approved by the NRC. Many of the changes were containment isolation valves similar to the RWCU system changes. Accordingly, no violation occurred with the plan revision and this URI is closed.

10. Exit Interview (30703)

The inspection scope and findings were summarized on February 18, 1994, 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, 296/94-01-01	NCV, Inadequate Second Party Check, paragraph 2.
260/94-01-02	VIO, Failure to Properly Perform Containment Visual Inspection Surveillance, paragraph 2.
259, 260, 296/94-01-03	VIO, Failure to Follow Procedure on Capacitor Bank Modifications, paragraph 5.
259, 260, 296/94-01-04	VIO, Missed Firewatch, paragraph 7.
259, 260, 296/94-01-05	URI, DG Fire Pump Auto Start Failure, paragraph 7.
260/94-01-06	VIO, Appendix R Design Errors, paragraph 7.
259, 260, 296/94-01-07	VIO, Failure to Make Required Notifications, paragraph 8.

Licensee management was informed that 1 IFI, 1 URI, and 1 VIO, were closed.

11. Acronyms and Initialisms

AOI	Abnormal Operating Instruction
ASOS	Assistant Shift Operations Supervisor
ATU	Analog Trip Unit
CCW	Condenser Circulating Water
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
DAD	Digital Alarming Dosimeters

DCN	Design Change Notice
DDFP	Diesel Driven Fire Pump
DG	Diesel Generator
ECCS	Emergency Core Cooling Sustem
EECW	Emergency Equipment Cooling Water
ENS	Emergency Notification System
FPP	Fire Protection Plan
FSAR	Final Safety Analysis Report
II	Incident Investigation
IR	Inspection Report
IVVI	In Vessel Visual Inspection
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOSP	Loss of Offsite Power
M&TE	Measuring and Test Equipment
MVAR	Megvar
NRC	Nuclear Regulatory Commission
PCB	Poly Chlorinated Biplanyl
PDD	Plant Drawing Deficiency
PER	Problem Evaluation Report
PMT	Post Modification Test
PORC	Plant Operation Review Committee
PS	Pressure Switch
QA	Quality Assurance
QC	Quality Control
RCIC	Reactor Core Isolation Cooling
RCW	Raw Cooling Water
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RWCU	Reactor Water Cleanup System
SBGT	Standby Gas Treatment System
SDBD	Shutdown Board
SI	Surveillance Instruction
SOS	Shift Operations Supervisor
SPOC	System Preoperability Checklist
SSP	Site Standard Practice
SSS	Shift Support Supervisor
TLD	Thermo Luminescent Dosimeter
TS	Technical Specifications
TVA	Tennessee Valley Authority
URI	Unresolved Item
UT	Ultrasonic Test
VIO	Violation
WO	Work Order
WP	Work Plan
WR	Work Request