U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Tennessee Valley Authority
Facility:	Browns Ferry Nuclear Plant, Units 1, 2 & 3
Location:	Corner of Shaw and Browns Ferry Roads Athens, AL 35611
Dates:	January 5 - February 15, 1997
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Approved by:	M. Lesser, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Units 1, 2 & 3
NRC Inspection Report 50-259/97-01, 50-260/97-01, 50-296/97-01

This integrated inspection included aspects of licensee plant operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection and includes inspections by the Region II Browns Ferry Project Engineer and two Region II Division of Reactor Safety Inspectors.

Operations

- A Unit 3 recirculation flow runback occurred due to decreased reactor water level when the 3A Reactor Feedwater Pump (RFP) was being removed from service for scheduled maintenance. Subsequent investigation identified that the water level decrease was caused by normal operation of the feedwater pump minimum flow valve. (Sections O1.1 and E8.3).

- Inspection and handling of new fuel was conducted well. (Section O1.2)

- Operations shift turnovers and Auxiliary Unit Operator rounds were conducted in a professional manner. Increased participation of Auxiliary Unit Operators in the turnovers was specifically noted. Panels in the Unit 2 Emergency Diesel Generator Auxiliary Board Rooms were not receiving proper levels of attention during AUO tours. One instance was identified in which the Operations lens cover convention was not correctly applied. (Sections O1.3 and O2.2)

- Two bolts failed on the actuator for the Unit 3 feedwater system startup control valve. The bolts were of lower grade than specified by the vendor. The licensee's identification, investigation, and corrective actions were conservative and thorough. (Section O2.1)

Maintenance

- A review of the alternate shutdown capability preventive maintenance and testing program concluded:

- The licensee has developed and implemented a program to monitor and maintain the Backup Control System consistent with Updated Final Safety Analysis report (UFSAR) commitments. (Section M1.1)

- Housekeeping in the areas inspected was good and equipment was well maintained. (Section M2.1)

- The licensee's self assessment of the Backup Control System was considered strong. (Section M7.1)

- During an inspection of the Unit 3 HPCI system, the inspectors noted that scaffolding had been erected directly over the HPCI turbine (in preparation for outage activities) with work in progress on the feedwater system. The inspectors concluded that stronger planning and better coordination should have been applied to the activities. (Section M2.1).

- A unexpected half-scram occurred during Unit 2 Scram Discharge Volume high level switch testing. The licensee investigated the incident and initiated good corrective actions. (Section M4.1)

- The details of several recent emergency diesel generator problems were reviewed. The issues did not have common ties and the licensee's corrective actions were appropriate. (Section M4.2).

Engineering

- The licensee's efforts to improve the overall quality of the Updated Final Safety Analysis Report (UFSAR) were reviewed. The licensee has initiated a comprehensive voluntary effort to identify and correct UFSAR discrepancies. Nuclear assurance and plant management actions have reinforced an overall vigorous effort and low threshold for identification. An Inspector Followup Item was opened to monitor the licensee's corrective actions. (Section E3.1)

- The licensee performed detailed evaluations and implemented adequate corrective actions to address several open items (Sections E8.4, E8.5, and E8.7).

Plant Support

- An inspection of the security diesel generator and diesel generator building identified housekeeping and component conditions that did not meet licensee management expectations (Section S2.1).

Report Details

Summary of Plant Status

Unit 1 remained in a long-term lay-up condition with the reactor defueled.

Unit 2 operated at power for the entire report period. On January 31, 1997, Unit 2 power was reduced to 30 percent power to perform repairs on the turbine building miscellaneous drain header. Unit 2 power was returned to 100 percent on February 8, 1997.

Unit 3 began the period operating at about 87 percent rated power in a coastdown for a scheduled refueling outage. On January 22, 1997, when the 3A Reactor Feedwater Pump (RFP) was being removed from service for planned maintenance, Unit 3 experienced a runback from 87 to 75 percent power. The RFP was immediately returned to service and Unit 3 power was restored to maximum allowable power. On January 24, 1997, Unit 3 power was reduced from 85 percent to 80 percent and then returned to maximum allowable power conditions in order to adjust feedwater system heater configurations and feedwater temperatures. For the remainder of the reporting period Unit 3 continued coastdown operation to a planned February 21, 1997 shutdown for the Cycle 7 refueling outage.

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the Updated Final Safety Analysis Report (UFSAR) that related to the areas inspected. No inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors. Paragraph E3.1 describes a review of the licensee's ongoing UFSAR improvement programs.

I. Operations

O1 Conduct of Operations

O1.1 Unit 3 Runback During Removal of the 3A Reactor Feedwater Pump (RFP)

a. Inspection Scope (71707, 92700, 93702)

The inspectors reviewed the licensee's actions in response to a Unit 3 recirculation flow runback that occurred during removal of the 3A RFP for scheduled maintenance.

b. Observations and Findings

On January 22, 1997, when the 3A RFP was being removed from service for scheduled maintenance, an unexpected reactor runback from 87 percent power to 75 percent occurred. 3A and 3B recirculation pump runback signals were received when reactor vessel water level reached 26.5 inches and the 3A RFP flow was reduced to less than 20 percent. The runback setpoint is less than 27 inches reactor water level with one RFP less than 20 percent flow. Reactor level was rapidly restored by the feedwater level control system. The RFP was returned to service.

Subsequently, the licensee determined that normal operation of the pump's minimum flow valve caused the reactor level to momentarily decrease below the runback setpoint. As the feedwater pump flow was reduced and the minimum flow valve opened, the ramp increase of the other two feedwater pumps was not rapid enough to prevent a temporary decrease in reactor water level.

The reduction of water level to less than the runback setpoint was initially suspected to have been caused by the RFP's discharge check valve not fully closing during the shutdown of the 3A RFP. One of these check valves had failed in April 1996. Section 3.8.1 of Inspection Report (IR) 96-04 describes NRC review of that incident.

On January 23, 1997, the 3A RFP was removed from service. Discharge check valve operation during the shutdown was determined to be satisfactory. The pump and check valve were removed from service for planned maintenance and for performance of scheduled check valve modifications. The vendor-recommended modifications included welding of the valve stem nut (which eliminated total reliance on the original nut-to-stem cotter pin locking arrangement) and installation of a sturdier valve disc alignment pin.

The licensee initiated installation of a modification which upgrades the Unit 3 feedwater control system to a digital system. This is similar to the modification previously installed on Unit 2. Removal of a feedwater pump from service on Unit 2 results in a much smaller reactor level decrease than occurred when the 3A RFP was removed from service. Section E8.3 of this report discusses additional details of this issue.

c. Conclusions

Although initially the licensee did not recognize that normal operation of the feedwater pump minimum flow valve had caused the reactor water level decrease, subsequent investigation was thorough. Training and Operations management developed a briefing package on the incident to encourage more active questioning by control room operators in such instances. The implementation of the digital feedwater modification on Unit 3 should improve feedwater system performance and reduce reactor water level variations during such evolutions.

01.2 New Fuel Receipt Inspection

a. Inspection Scope (71707)

The inspectors reviewed activities associated with the licensee's receipt of new fuel in preparation for the Unit 3 outage. Fuel bundle inspection was observed. In addition, an inspector observed licensee radiation control activities associated with processing the fuel transport vehicle into the protected area and unloading of the fuel into the Unit 1 equipment airlock.

b. Observations and Findings

On January 7, 1997, one of the inspectors observed radiation control activities associated with processing of the fuel transport vehicle into the protected area. On January 7 and 14, 1997, the inspectors observed unloading of the wooden shipping containers into the Unit 1 equipment airlock.

The inspectors also observed fuel bundle inspection activities. The individuals involved in the receipt process were knowledgeable of their assigned responsibilities. The inspectors noted that the Assistant Unit Operators (AUOs) who performed the fuel inspections were thorough. A specific example was identification of a small piece of foreign material in one of the bundles. The material was removed and retained for further analysis.

During the fuel inspection, a tie rod on one of the fuel assemblies was found to be bent. The licensee returned the assembly to the vendor for necessary repairs. Subsequently, the fuel rod with the damaged tie rod attachment was removed from the assembly, repaired, and placed back into the assembly. The fuel bundle was returned to the site, inspected by the licensee, and placed into the spent fuel pool. The manufacturer is performing additional reviews into the cause of the deficiency.

The inspectors observed that activities regarding new fuel handling were consistent with descriptions contained in a TVA to NRC letter, dated November 22, 1996. This letter was a resubmittal of a request for exemption from 10 CFR 70.24 criticality monitoring requirements. Specifically, the letter addressed strict limits for the maximum number of fuel bundles allowed out of approved storage locations at any given time. The licensee currently has two procedures; General Operating Instruction GOI-100-2 New Fuel Operations, and Site Standard Practice SSP- 12.12, Fuel Receipt, Storage, and Use, which address the maximum quantity of nuclear fuel bundles allowed out of approved storage locations. The inspectors determined that the activities were conducted in accordance with the procedures.

c. Conclusions

The inspectors concluded that new fuel receipt activities were performed in a satisfactory manner. The inspectors noted that the individuals involved in the fuel receipt process were knowledgeable of their responsibilities and the AUOs, during their inspections of the new fuel bundles, were thorough.

01.3 Operations Shift Turnover and AUO Rounds

a. Inspection Scope (71707)

During the inspection period, the inspectors attended several Operations shift turnover meetings and accompanied Auxiliary Unit Operators (AUOs) on plant tours.

b. Findings and Observations

The inspectors observed several shift turnovers during the inspection period, and noted that involvement of the AUOs during these meetings had substantially improved over previously observed turnovers. AUOs were required to provide briefs on their areas of responsibility. The briefings indicated that the AUOs were prepared for the turnovers.

On February 6, 1997, an inspector accompanied the outside AUO during performance of evening shift rounds. The inspector observed that the AUO performed tasks in a generally conscientious manner; however, upon subsequent review of Operating Instructions 2-OI-27 and 3-OI-27, Condenser Circulating Water System, Revisions 25 and 16, respectively, the inspector noted that the AUO had not performed an activity exactly as prescribed in these procedures. Licensee management was informed of the details. The activity did not involve a safety significant system. The inspectors also noted that operations group self-assessments had not identified differences between prescribed procedural guidance and how the activity was actually performed.

c. Conclusions

The inspectors concluded that the shift turnovers were good. Input by AUOs during the turnovers was sufficiently detailed. AUOs demonstrated increased ownership of their assigned plant equipment and areas of responsibility. Observed AUO rounds were adequately performed.

02 Operational Status of Facilities and Equipment

02.1 Feedwater System Start-up Control Valve Actuator Bolting Failure

a. Inspection Scope (71707, 92700, 93702)

The inspectors reviewed the licensee's actions in response to identification of failed bolts on the actuator assembly for the Unit 3 Feedwater System Start-up Control Valve (3-LCV-3-53).

b. Observations and Findings

On January 24, 1997, during performance of scheduled feedwater pump preventive maintenance, workers noted that the air-operated actuator for Start-Up Feedwater Control Valve 3-LCV-3-53, was bent about 35 degrees from its designed vertical position. Two of four actuator hold-down bolts were sheared and the remaining two bolts were bent. The inspectors were notified and examined the bent actuator and hold-down bolt conditions. Because the actuator was bent, the control valve assembly could not function as designed. Licensee personnel isolated the valve from the rest of the feedwater system by shutting the valve's inlet and outlet isolation valves. The manual bypass valve for the start-up feedwater system was not affected by the problem and was available for start-up feedwater system operation.

A preliminary metallurgical evaluation of the broken bolts concluded that the event was initiated by vibration-induced cracking and eventual ductile failure of the remaining bolt metal.

The licensee determined that lower-grade bolts than those called for by the vendor had been used. It was also noted that if the vendor recommended bolts had been used, it was unlikely that the bolts would have broken. It was also noted that higher-grade bolt torque values may have been used during past actuator repairs. This torque, if applied to the lower-grade bolts, could have contributed to the bolting failure.

Licensee maintenance personnel immediately performed necessary control valve and actuator repairs using an actuator, valve yoke, and bonnet assembly from Unit 1 Start-Up Control Valve 1-LCV-3-53. The actuator and valve assembly were returned to service on January 29, 1997. The licensee verified that the bolts for the corresponding Unit 2 valve actuator were of the proper grade.

c. Conclusions

The inspectors concluded that licensee's actions, including lessons learned training and repairs using Unit 1 parts, were appropriate. The inspectors also found that corrective actions involving retraining in use of proper bolting material was adequate.

02.2 Reactor and EDG Building Tours

a. Inspection Scope (71707)

On several occasions during the report period, the inspectors toured accessible plant areas in accordance with guidance presented in IP 71707.

b. Observations and Findings:

The inspectors toured the Unit 2 Emergency Diesel Generator (EDG) Auxiliary Board Rooms and observed the following anomalies in status lights. The 1B Offgas Dilution Air Fan status light was clear and illuminated, but the 2B and 3B Fan status lights were diffused and illuminated. The emergency power available light was not illuminated on the 1B fan, but was illuminated on the 1A and 1C fans. Auxiliary Unit Operators (AUOs) determined this was due to a burned out bulb, which was immediately replaced. The D EDG Exhaust Fan A status light was also diffused red, but not illuminated. Discussions with two AUOs indicated that the licensee's lens cover convention is such that if a status light is normally lit it should have a diffused lens cover of the appropriate color. Diffused lens covers which are not lit would indicate an abnormal condition. In addition, when equipment is alternated, the lens cover should be changed to match the lens cover convention. The AUOs stated that during board walkdowns and routine tours, the AUOs typically verify proper alignment of equipment by this convention. These two issues were brought to the attention of the Unit 2 Shift Manager, who

initiated Problem Evaluation Report (PER) 970167. The licensee's review of the issue identified that the 1B Offgas Dilution Air Fan should have had a diffused lens cover, and that the EDG D Exhaust Fan A should have had a clear lens cover. The licensee confirmed that the equipment was in the proper alignment, but the lens covers had not been properly changed when equipment was alternated. The licensee conducted additional reviews beyond the EDG Auxiliary Board Rooms as part of the PER actions.

The inspectors noted that an instance of improperly positioned switches for the Unit 3 EDG Auxiliary Board Room fans was identified by the NRC in IR 96-12. That issue was also identified through an anomaly in the lens cover convention. A violation was issued in IR 96-12 addressing the improperly positioned switches. As noted above, in this instance, the involved switches and equipment were properly aligned.

c. Conclusions

The inspectors concluded that the licensee was not rigidly applying the lens cover convention in all cases, and the EDG Auxiliary Boards were not receiving the appropriate level of attention during AUO routine rounds. The licensee's response to this issue was good.

02.3 EOI Tools and Equipment Inventory Checklist

a. Inspection Scope (71707)

During the inspection period, the one of the inspectors selected four Emergency Operating Instruction (EOI) boxes and verified that items listed on the associated 0-GOI-300-1, Attachment 15.22, EOI Tools and Equipment Inventory Checklist, were in the selected boxes.

b. Findings and Observations

The inspector selected four EOI boxes, one from each of the Reactor Buildings, and one from the Unit 2 Control Room. The inspector observed as Operations personnel opened each of the four selected boxes and inventoried the contents. The boxes were in good condition. The inspector did not identify any missing items and the condition of the items appeared to be good. The inspector also verified that the EOI Appendices located in the boxes were the latest revision.

02.4 High Pressure Coolant Injection System Inspection

a. Scope (71707)

The inspectors conducted a general walkdown and inspection of the Unit 2 and Unit 3 High Pressure Coolant Injection (HPCI) Systems.

b. Findings and Observations

During the inspection period, the inspectors conducted a HPCI System general walkdown and inspection on Units 2 and 3. The inspectors questioned a temporary hose which was attached to a drain line downstream of the steam trap from the HPCI turbine steam supply line on Unit 2. Subsequently, the licensee removed the hose. The inspector also noted that scaffolding had been erected over the Unit 3 HPCI system. The scaffolding issue is addressed in Section M2.2 of this report. No other deficiencies were identified. General housekeeping and material conditions were satisfactory.

06 Operations Organization and Administration

06.1 Plant Operations Review Committee (PORC) Meeting

a. Inspection Scope (71707, 40500)

On January 10, 1997, the inspectors attended a special licensee PORC meeting to assess PORC meeting activities and compliance with approved TS requirements.

b. Observations and Findings

The inspector verified that a quorum was present. Items reviewed and recommended for approval were determined not to represent unreviewed safety questions. During the meeting, the following items were presented and approval was recommended by the PORC:

- An Updated Final Safety Analysis Report (UFSAR) change to clarify Standby Gas Treatment System (SGTS) and secondary containment operation for degraded conditions.
- LER 296/96-007, Unplanned ESF Actuations
- LER 296/96-008, Loss of ECCS Division II Instrumentation Renders ECCS Inoperable. The PORC noted that the root cause of the failure had not yet been determined and the cause and associated corrective actions would need to be addressed in a supplemental report to LER 50-296/96-004.
- Five additional UFSAR change requests to correct deficiencies or clarify descriptions.

c. Conclusions

The inspector concluded that PORC activities were acceptable. Activities performed followed prescribed actions contained in TS Section 6.5.1 and associated subsections. Committee discussion of issues was thorough and PORC recommendations were appropriate.

08 Miscellaneous Operations Issues (92901)

08.1 (Closed) LER 296/95-04, Unplanned Engineered Safety Features (ESF) Actuation Following Transfer of 480V Shutdown Board 3A to its Alternate Supply. The cause of this ESF actuation was personnel error. This issue was reviewed and a violation issued in Inspection Report 50-259,260,296/95-56, issued December 4, 1995. The licensee's response was reviewed and the violation closed in IR 96-08. This LER did not provide additional information not already reviewed by the inspectors. Based on the satisfactory closure of the violation, this LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Shutdown From Outside Control Room

a. Scope (62700)

The Updated Final Safety Evaluation Report (UFSAR) Section 7.18 states that the Backup Control System (BCS) is to provide 1) a means to safely shutdown the plant from locations outside the Main Control Room following an orderly evacuation and 2) a sufficient complement of controls and instrumentation at these locations to bring the plant from an operating condition to cold shutdown.

The inspection was performed to determine that the licensee has developed and implemented a preventive maintenance (PM) and testing program to ensure that alternate shutdown capability from outside the main control room is monitored, maintained and operable.

The inspectors reviewed the PM performance and schedule, maintenance work order history, the frequency of instrument calibrations and functional testing from the computer tracking list of PMs and functional testing of the Backup Control System, instrument calibration process, and the last functional test for selected systems to determine that the licensee has monitored and maintained the BCS in accordance with the UFSAR.

b. Observations and Findings

Instrumentation and controls to achieve and maintain hot and cold shutdown as required by 10 CFR 50 Appendix R are provided by a separate BCS for each unit. This is supplemented by manual actions at local component control stations. The inspector determined that the Unit 2 BCS was functionally tested during restart in 1991 and has been functionally tested at each refueling outage subsequently as required by the UFSAR. Unit 3 was functionally tested during restart in 1995 and was scheduled to be functionally tested at the next refueling outage. Systems and components required to satisfy the alternate shutdown capability at Browns Ferry were described in the licensee's UFSAR

Section 7.18. Although the site has no Technical Specification requirements for routine testing, the licensee performed functional testing of BCS controls on a refueling outage basis consistent with the UFSAR.

The inspectors verified that the licensee had successfully performed the required functional tests at the required frequency by reviewing portions of the procedures and the computer surveillance tracking system. Adequate instructions had been included in the procedures to verify that control of essential equipment and instrumentation for cooldown and shutdown of the reactor can be transferred to and operated from the backup control panels outside the main control room. Also, the isolation of the BCS from the main control room was verified.

The inspectors discussed the calibration process with Instrumentation and Controls personnel to verify adequate testing has been performed. The test is periodically initiated by the distribution of a repetitive task form generated from the computer surveillance tracking system which identifies the loop to be calibrated and the schedule. The licensee then consults the system instrument maintenance index which identifies the instruments involved, the test procedure and the scaling and set point document for vendor and technical data. The inspectors reviewed the process, documents and the last PM calibration performed for the Reactor Core Isolation Cooling (RCIC) system flow control (LCI-2-F-71-36) and the Residual Heat Removal Service Water (RHRSW) pressure loop (LCI-0-P-23-60) and considered the process adequate. Frequency of the calibrations was verified through work orders and the computer surveillance tracking system.

c. Conclusions

The inspectors concluded that the licensee has developed and implemented a program to monitor and maintain the Backup Control System consistent with the UFSAR commitment.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Condition of Remote Shutdown Areas and Equipment

a. Scope (62700)

The inspector conducted a walkdown of the Backup Control System (BCS) and associated switchgear and motor control centers (MCC) to determine the adequacy of housekeeping and the condition of equipment.

b. Observations and Findings

The walkdown included the areas where remote shutdown equipment was located. The following areas and equipment were inspected:

Unit 2:

- Control Room and panels associated with control room abandonment.
- 4kV shutdown boards, 480V Reactor Motor Operated Valve (RMOV) board 2A, 480V shutdown board 2A & 2B, and 250 Vdc RMOV board 2A
- Backup Control Panel 2-25-32 and Auxiliary Instrument Room

Unit 3:

- Control Room
- 4kV shutdown boards, 480V RMOV board 3A & 3B, and 250 Vdc RMOV board 3A & 3B
- Emergency Diesel Generators and Backup Control Panel 3-25-32

The inspector found that the areas inspected were clean, neatly painted, and well lighted. Instrument panels and switchgear were in good condition and clearly labeled. Wiring inside panels was neatly bundled and tied off. No trash was evident.

c. Conclusions

The inspector concluded that housekeeping in the areas inspected was good and equipment was well maintained.

M2.2 Scaffolding In Unit 3 High Pressure Coolant Injection (HPCI) Area

a. Inspection Scope (62707, 92902)

The inspectors examined work control and risk assessment activities associated with the placement of scaffolding around the HPCI system.

b. Observations and Findings

During the inspection of the Unit 3 HPCI system (Section O2.4), the inspectors noted that a scaffold had been erected in the overhead directly above the HPCI turbine. The scaffolding appeared to be constructed in accordance with procedural restrictions and was firmly anchored to the ceiling and a ladderway. 0-TI-264, Scaffolding and Temporary Platforms provides specific requirements for seismic considerations for such scaffolding.

The inspectors have previously reviewed licensee scaffolding controls and did not identify significant deficiencies. Discussions with licensee management indicated that this scaffold had been erected as a pre-outage activity in preparation for maintenance to be performed during the upcoming refueling outage. The inspectors noted that the scaffold had been erected with work activities involving the Unit 3 feedwater system in progress. Additionally, the licensee had recently removed HPCI from service for a short duration outage and did not erect the scaffolding during that period.

c. Conclusions

Although no adverse safety significant problems resulted from erection of the scaffolding, the inspectors concluded that stronger planning and coordination could have ensured that the scaffolding was erected at a time which presented a lower potential risk to safety system operability. At the close of the report period, the licensee was reviewing potential enhancements to address inspector observations.

M4 Maintenance Staff Knowledge and Performance

M4.1 Unit 2 Half-Scram During Performance of Scram Discharge Volume Testing

a. Inspection Scope (61726)

The inspectors reviewed activities associated with functional testing of the Unit 2 Reactor Protection System (RPS) Scram Discharge Volume (SDV) high water level switch. Inspectors also reviewed licensee follow-up in response to an unexpected half-scram which was received during testing.

b. Observations and Findings

On January 7, 1997, an unexpected half-scram occurred during functional testing of Unit 2 RPS SDV high level circuitry. While performing surveillance test, 2-SI-4.1.A-8(E), RPS High Water Level In Scram Discharge Tank Functional Test, Revision 11, a second, unexpected half-scram occurred. The half-scram was caused by an unanticipated high water level condition in the SDV instrument volume which actuated SDV RPS level switch 2-LS-85-45D.

A test valve (ball valve located on a test rig) was opened in accordance with step 7.10.11. After switch actuation personnel were to immediately shut the valve and verify receipt of an expected half-scram. In accordance with the procedure, after personnel shut the test valve and verified the half-scram, they opened the SDV drain and drained the instrument volume. Then the drain valve was closed and the half-scram was reset. Apparently, the test valve became partially opened and level once again increased to the high level setpoint and initiated the second unexpected half-scram signal.

All further testing activities were immediately stopped by the Lead Test Performer. Testing personnel reviewed test rig and SDV system alignment and determined that water must have leaked through the partially open test valve. The test rig demineralized water supply valve and calibration valve were again closed, the SDV instrument volume was drained and the half-scram was reset. Licensee management conducted an investigation to determine how the valve became partially open. The licensee concluded that the most likely cause was that the valve was inadvertently bumped open after being initially closed. The valve is part of a test rig that was laid on the floor after the worker initially shut the valve.

c. Conclusions

The Operations manager had been directly observing the test activity. He stated to the inspectors that he had observed the worker shut the test valve. He also stated that the workers were actively utilizing the procedure and applying self checking techniques. The valve was replaced, the procedure was revised, and lessons learned from this event were presented to other plant personnel. The inspectors concluded that no regulatory requirements were violated and that the licensee's corrective actions were appropriate.

M4.2 EDG Material Condition Concerns

a. Inspection Scope (62707)

Inspection Report (IR) 96-10 and Inspector Followup Item (IFI) 96-10-04 discussed an increase in Emergency Diesel Generator (EDG) problems from August to October 1996. The issues were partially reviewed in IR 96-12. This inspection reviewed additional items of IFI 96-10-04 to determine the adequacy of the licensee's review and corrective actions.

b. Observations and Findings

On September 8, 1996, the 2B EDG experienced voltage and frequency swings when the mode selector switch was placed in parallel with the system. Also noted was excessive fuel rack movement, revolutions per minute swings from 900 to 930, and an engine coast down time of 3 minutes instead of the usual 11.5 minutes. These issues were identified during routine testing. The licensee initiated Level B Problem Evaluation Report (PER) 961214 for this issue. Corrective actions included multiple EDG runs to troubleshoot the problem. The licensee identified several causes for this issue, including inadvertently closing the fuel cutoff valve during painting activities (this issue was addressed as one of three deficiencies in Violation 50-259,260,296/96-10-02 regarding EDG work oversight), potentially sticking fuel injectors, unstable output of the electronic governor, and unstable mechanical governor operation due to a pilot valve plunger. The licensee's troubleshooting activities for this issue were extensive, and corrective actions included replacing the mechanical and electronic governors.

On September 12, 1996, indications of a control circuit ground on the 2D EDG were received in the control room. The licensee determined that painters in the area had sprayed down a cable during cleaning. The cable was a connection for the Lube Oil Low Temperature switch. The ground cleared quickly as the cleaning spray evaporated. This deficiency was an additional example of Violation 50-259,260,296/96-10-02 regarding EDG work oversight.

On October 4, 1996, the 3D EDG failed to start during redundant start tests due to failure of start circuit #1. This occurred while the EDG was inoperable for two-year maintenance. During maintenance, several time delay relays had been replaced. During post maintenance testing, relay 3-RLY-082-D/NFLDA failed to close, which caused the start circuit problem. This relay was replaced under Work Order (WO) 96-012813-000. The failure of these components is trended in the licensee's trending program, and the components have not exhibited a high failure rate. The inspector noted that the system engineer was sensitive to potential aging problems associated with this and other EDG components.

On October 12, 1996, during routine surveillance, following a start signal, the 3A EDG received no voltage or frequency response on panel 3-9-23A in the main control room. Licensee troubleshooting identified the cause to be a blown fuse in the sync switch circuit (3-FU-211-3EAA). The fuse was replaced per SSP-12.56, Fuse Control Program, and the surveillance was completed satisfactorily.

c. Conclusions

The inspectors concluded that the EDG problems identified in IFI 96-10-04 were isolated examples and did not have a common tie. The licensee's review was good, and appropriate corrective actions were taken. Based on the inspector's review, this IFI is closed.

M7 Quality Assurance in Maintenance Activities

M7.1 Self Assessment of the Backup Control System (BCS)

a. Scope (62700)

The licensee had recently performed a vertical slice audit (NA-BF-97003) of the BCS. The inspectors reviewed the preliminary findings.

b. Observations and Findings

The audit was an indepth review using eight auditors for ten days and covered all aspects of the BCS including review of industry operating experience, walkthrough of control room abandonment procedure, comparison of design criteria with licensing basis, reviews of test procedures and functional performance, instrument calibrations and PM performance, maintenance and plant support. Although the audit identified some minor discrepancies, the issues did not prevent the

fulfillment of the shutdown function. Overall, the licensee concluded that design requirements are incorporated properly into maintenance and test procedures, procedures and equipment are in order, and testing has been routinely performed.

Problem Evaluation Reports were issued to resolve the minor discrepancies identified by the audit. The evaluation was still in progress at the end of this inspection period.

c. Conclusions

The inspector's observations were in general agreement with the licensee audit conclusions. The audit was considered thorough and detailed.

III. Engineering

E3 Engineering Procedures and Documentation

E3.1 Updated Final Safety Analysis Report (UFSAR) Discrepancies

a. Inspection Scope (37551, 40500, 92903)

Since February 1996 (IR 96-03), the resident inspectors have specifically reviewed many UFSAR descriptions during inspections of plant processes and equipment to verify that UFSAR descriptions were accurate. Several discrepancies have been identified. Additionally, the licensee has identified numerous other discrepancies and areas requiring clarification as a result of an extensive voluntary effort to review and correct discrepancies in the UFSAR. The inspector reviewed the licensee's actions and the UFSAR discrepancies identified since early 1996. The inspector assessed the items and the licensee's actions in accordance with guidance promulgated in NUREG 1600, Policy and Procedure for Enforcement Actions, Departures from the UFSAR.

b. Observations and Findings

Since February 1996, the inspectors have identified the following UFSAR discrepancies:

- The UFSAR states that spent fuel pool high or low levels will actuate alarms in the control room. Only low-level conditions actuate an alarm in the control room. (IR 96-03)
- The UFSAR states that refueling takes place on an approximate annual basis. Refueling takes place about every 18 months. (IR 96-03)
- Several sections of the UFSAR associated with electrical systems had not been updated to reflect return of Unit 3 to power operations. (IR 96-03)

- UFSAR values for maximum spent fuel pool heat load were not updated to incorporate licensing basis information involving a rerack amendment. (IR 96-05)

- The circulating water system traveling water screens and screenwash systems were not being operated as described in the UFSAR. The systems are not controlled by traveling screen differential pressure. (IR 96-08)

Other related issues such as an UFSAR described control room annunciator disabled without a safety assessment have been identified by NRC inspectors and were addressed separately in previous inspection reports.

The licensee has initiated a significant effort to compare the UFSAR with how the plant is actually designed, operated, and maintained. The effort includes evaluation and resolution of identified discrepancies by application of the established corrective actions program. At public meetings on July 10, 1996, and August 12, 1996, the licensee briefed the NRC staff on the activities at the three TVA nuclear sites to ensure compliance with the UFSAR. Additional discussion of the UFSAR Validation Program Plan was held at a meeting on August 23, 1996. On October 16, 1996, TVA updated the NRC staff on the UFSAR review program at a meeting in the Region II office.

The licensee's actions include detailed reviews of the UFSAR text by Operations personnel and the responsible site organization. Technical Instruction 0-TI-353, UFSAR Functional Review Criteria, outlines the method to confirm UFSAR contents are consistent with the design bases, physical plant configuration, and operating procedures. To date, the licensee has identified discrepancies in four categories: Processes and personnel, descriptions not updated, inconsistencies between UFSAR and plant equipment, and abandoned equipment descriptions. At BFN, the central corrective actions program element in the review effort is Problem Evaluation Report (PER) 960204 which was initiated on March 15, 1996. To date, approximately 1340 issues have been identified in the corrective actions for PER 960204. Some of these issues are questions or inquiries and may not be actual deficiencies. Engineering incorporated the information into PER 960204. The issues were promptly reviewed for impact on operability by engineering personnel and management. To date, the licensee has concluded that none of the identified items affected operability or represented unreviewed safety questions. Currently, about 750 items remain open. Site Engineering is reviewing the items, closing approximately 20 items per week. UFSAR Amendment 13 was completed in October 1996. The licensee intends to complete resolution of all remaining issues by May 1998. Nuclear Assurance and Licensing evaluates the reviews.

UFSAR review is also included in vertical slice assessments similar to Safety System Functional Inspections which the licensee intends to continue as part of the overall audit plan. Vertical slice assessments

of the Main Steam and Electro-Hydraulic Control Systems have been completed. While no significant deficiencies were identified, improvement areas were noted.

In routine reviews of PERs and attendance at Management Review Committee meetings, the inspectors have noted that the licensee has clearly established a low threshold for identification of UFSAR discrepancies. Several UFSAR issues have been identified by on-shift Operations personnel. Additionally, Nuclear Assurance efforts have also supported a thorough review and low threshold. For example, Nuclear Assurance assessment NA-BF-96-080 identified several conflicts with the UFSAR associated with four major plant systems after UFSAR Amendment 13 was complete. PER 970226 was initiated to address why the issues were not identified during the validation of the amendment.

The licensee has also initiated significant efforts to improve the quality of safety assessments and evaluations after NRC and independent reviewers identified weaknesses in those areas in 1996. Additionally, the licensee has identified procedural discrepancies associated with application of the "Living" FSAR.

The inspectors verified that the five issues specifically identified by the NRC have been addressed. All except the circulating water system operation description, have been closed out. The inspector noted that the UFSAR has been revised to indicate that the traveling screen systems can be operated in manual. In each of the five issues, the UFSAR was or will be revised to match the actual conditions. In the case of the Unit 3 electrical systems, the licensee was still within the time period allowed by 10 CFR 50.71 for UFSAR updates. The impact of Unit 3 restart on the electrical system descriptions will be addressed in UFSAR Amendment 14, expected to be completed in March 1997. The inspectors reviewed the licensee identified UFSAR issues listed for PER 960204 and described in numerous PERs. The inspectors concluded that it was likely that the licensee's program would have identified the deficiencies noted by the NRC inspectors.

c. Conclusions

The inspector concluded that the licensee has initiated a comprehensive voluntary effort to identify and correct UFSAR discrepancies. To date, the licensee has appropriately expanded the scope of the initiative. Nuclear Assurance and plant management actions have reinforced an overall vigorous effort and low threshold for identification. In accordance with the guidance in NUREG 1600, Policy and Procedure for Enforcement Actions, Departures from the UFSAR, Unresolved Item 50-259, 260, 296/96-04-08, Final Safety Analysis Report Deficiencies, is closed. Inspector Followup Item (IFI) 50-259,260,296/97-01-01, Resolution of FSAR Discrepancies, will be utilized to monitor the licensee's corrective actions to completion.

E8 Miscellaneous Engineering Issues (92902)

E8.1 (Closed) Licensee Event Report (LER) 50-296/95-07, Unplanned Engineered Safety Feature Actuation Following Transfer of 480V RMOV Board 3B to its Normal Power Supply after the Replacement of a Temporary Normal Supply Breaker.

The licensee determined the root cause to be a failed Amptector Direct Trip Actuator (DTA) on the permanent normal supply breaker. The device was replaced. The licensee forwarded the failed device to the vendor for a formal failure analysis. Vendor review of assembly and its manufacturing processes determined that a modification should be added to increase the component's reliability. As a result of this issue, the vendor, Westinghouse, generated a Potential Safety Issue on December 14, 1995. The licensee generated work requests to replace all DTAs (18 in total) with modified DTAs received from the vendor. These replacements are to be coordinated with the next scheduled breaker preventive maintenance activities (24-36 month intervals), which are currently in progress. The licensee's corrective actions for this issue were satisfactory.

E8.2 (Closed) Unresolved Item (URI) 50-259,260,296/96-04-08, Final Safety Analysis Report Deficiencies. Review of this item is discussed in Section E3.1 of this report. This URI is closed. IFI 259,260,296/97-01-02, Resolution of UFSAR Discrepancies, remains open pending inspection of the licensee's actions to resolve the issues.

E8.3 (Open) Inspector Followup Item (IFI) 50-296/96-04-04: Failure of Feedwater Pump Discharge Check Valve. In April 1996, Unit 3 scrammed after the 3C feedwater pump discharge valve failed. The disc had separated from the stem. The valves were inspected on both units and degraded conditions were noted on several of the valves. Inspection of the operational and maintenance aspects of this issue was documented in Inspection Report 96-04. The inspectors concluded that the licensee's previous corrective actions in response to continued degradation of the check valves prior to the failure had not been strong. Since that time, modifications have been completed to address the issues. These efforts included removal of the air assist feature for the closure of the valve.

Since the restart of U3, there have been several suspected reverse feedwater flow incidents during removal of a feedwater pump from service. In one case, a reactor runback occurred. Initially, the licensee's investigation focused on the discharge check valves "hesitating" to close, permitting reverse flow from the other feedwater pumps. It was postulated that the air operator portion of the valve may have been inhibiting disc closure due to the manner in which the air operation had been modified. Additionally, it was noted that on several valves, packing may have been inhibiting free motion of the disc.

The inspectors discussed the issues with engineering personnel and closely reviewed plant computer plots of several recent examples of removal of feedwater pumps from service. The information indicated that

the reactor water level decreases (and the resulting runback) were caused by the reactor feedwater pump minimum flow valve opening during reduction of feedwater pump speed. The minimum flow valve appeared to be operating as expected. The other feedwater pumps responded by increasing flow but were limited to a maximum "ramp" rate of increase so a small level decrease is observed before level is restored to normal. On Unit 3, the transient is more severe since the digital feedwater control modification is not yet installed. Removal of a feedwater pump on Unit 2 affected level in a similar manner but with less magnitude since the other feedwater pumps responded more rapidly.

Information indicates that the recent suspected "reverse" flow incidents were not failures of the check valves to shut. No other scrams or pressure spikes indicative of a "hesitating" disc have occurred since the April 1996 scram. Recent inspection of valve internals indicate that the modifications intended to strengthen the valve disc-to-stem connection were successful. The licensee has completed additional measures to ensure that the spring "assist" on the disc closure will not be inhibited by packing or air operator binding. The licensee is continuing to review potential modifications to the check valves and/or feedwater systems, including restoration of the ability to operate the disc from the control room. The IFI remains open pending review of the licensee's additional actions.

E8.4 (Closed) URI 259,260/93-011-02: Explanation of the Stress Intensity Shown in the Summary Stress Report for Reactor Vessels 1 and 2. The licensee responded to this issue by letter dated May 12, 1993. This item was opened to address apparent questions about discrepancies in the licensee's Summary Stress Report. The inspectors discussed this item with licensee engineers and reviewed information provided. A summary of licensee information or the engineering explanation is stated below to answer four questions related to this open item:

- B&W used the elastic-plastic methodology permitted in Section N-417.5 of the 1965 American Society of Mechanical Engineers (ASME) Section III Code to justify and qualify the component when the primary plus the secondary stress exceed the 3Sm allowables.

- The peak stress, F, is defined in ASME Section N-413(b)(5) as "The increment of stress in a region under consideration which is additive to the primary and/or secondary stress by reason of a concentration (notch) or a localized thermal stress." The addition of the F stress is algebraically additive at the directional stress level to the Primary Plus Secondary Stress. Thus, the F stress can either reduce or increase the directional stresses and stress intensity at a particular point. This could result in a peak stress less than the primary plus the secondary stress. But the range between the maximum stress and the minimum stress calculated for the peak stress and used for the fatigue analyses are always higher than the range of the primary plus secondary stress.

- Based on the above conservative calculation, the fatigue analyses in Browns Ferry Plant used a higher value of the peak stress and was considered to be valid.

- The stress intensities in the sketch on page B-16-10 of the Summary Stress Report (Volume 4) are the sum of those on page B-16-8 sketch and those from the page B-16-9 piping loads, with reductions in the piping load stresses for junctures 2 and 5 to reflect the larger-than-minimum thickness of those sections. Therefore, the final primary plus secondary stress intensities shown on page B-16-10 are traceable.

Based on the information reviewed and the explanation from the licensee engineers, this item is closed for both units.

E8.5 (Closed) Violation 260/95-015-03: Failure to Implement the Corrective Action Program. The licensee responded to this violation by letter dated April 13, 1995. This violation was identified because the licensee did not establish a corrective action program to review a potential deficiency of Unit 2 drywell structural steel cover plates.

The inspectors discussed the issue with the licensee engineers and reviewed the licensee response. The inspectors also reviewed PER 950324 and calculation No. CD-Q2303-950053 (Rev. 0 & 1). The calculation was very thorough and included scope, AISC Requirements, methodology, computation and analyses, summary of the results, and conclusions. Basically, the licensee reviewed all the modifications for the Unit 2 drywell platform steel beams; sorted the beams with the additions of the cover plates; filtered the beams with partial lengths of cover plates added; selected seven beams as representative samples for the worst cases; and performed an adequacy verification for the cover plate lengths. All the seven beams reviewed had adequate cover plate lengths without modifications.

Based on the inspector's review, this violation was closed.

E8.6 (Open) IFI 260/95-041-01: Emergency Diesel Generator (EDG) 1A Turbocharger Inspection. This IFI was open to evaluate the results of the licensee vendor visits and to evaluate the examination of 1A EDG's biannual inspection performed in June 1996.

The inspectors reviewed three laboratory reports 693.A01, 693.A02, and 693.A04 performed by Materials Analytical Services, Atlanta, Ga. for EDG Turbocharger gear crack examination, sent from TVA Browns Ferry Nuclear Plant. Report 693.A01 identified no cracks. Reports 693.A02 and 693.A04 identified that the failures of the gears were due to quench cracking which allowed fatigue cracks to propagate until final catastrophic failure. The above analyses confirmed the licensee preliminary conclusion of the quench cracks contributing the failure.

The licensee sent engineers to visit the vendors for inspection and investigation about the manufacturing process for the turbocharger gears. The report has not been completed. The evaluation of the results for the biannual inspection on EDG 1A Turbocharger performed around June 1996 was also not completed. This IFI remains open pending completion of the licensee's evaluation.

E8.7 (Closed) Violation 296/95-057-01: Failure to Install Modifications in Accordance with Design Drawing Requirements. This violation was identified because the licensee failed to construct tubing and piping supports as specified by the design drawings and the specification. The licensee response to this violation dated January 12, 1996, stated that the five examples stated in the Notice of Violation were due to personnel errors and were considered to be isolated cases.

The inspectors discussed this violation and the corrective actions with the licensee engineers. The inspectors also reviewed the response and the associated corrective documents such as Problem Evaluation Reports (PERs) 95-1304, 95-1440, 95-1439, 95-1704 and Work Orders 95-18882-00, 95-18596-00, 95-19409-00, 95-14421-10. The inspectors concluded that the licensee response was adequate and the corrective actions were acceptable. This violation was closed based on the adequate actions taken by the licensee.

IV. Plant Support

S2 Status of Security Facilities and Equipment

S2.1 Condition of the Security Diesel Generator and Generator Building Area

a. Inspection Scope (71750)

The inspectors inspected the on-site Security Diesel Generator and Generator Building area.

b. Observations and Findings

On January 14, 1997, the inspectors, during a routine tour of the Security Diesel Generator area, noted that the operational condition of the security diesel appeared good; however, the following discrepancies were identified:

- A junction box cover (7120) was not properly attached.
- 1991 Work Request (WR) (C087210) tag was present on a wiring panel. The inspectors, after discussions with Security, concluded that this WR was no longer active. The tag was removed.
- Several ladders and a portable space heater were not properly stored.

- Diesel battery connections were oxidized and required cleaning.
- General area housekeeping was poor.

The inspectors contacted appropriate licensee management personnel for correction of the issues. The maintenance manager was also informed. WR C320333 was issued to address the general housekeeping issues.

c. Conclusions

Licensee security and maintenance personnel promptly addressed the deficiencies. The licensee issued WRs to ensure correction of general area items. On a subsequent inspection of the area, the inspectors noted that the identified issues had been adequately addressed.

V. Management Meetings

X1 Exit Meeting Summary

The resident inspectors presented inspection findings and results to licensee management on February 18, 1997. Other meetings to discuss report issues were conducted on January 31 and February 7, 1997. The licensee acknowledged the findings presented. Proprietary information is not included in this inspection report.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

T. Abney, Licensing Manager
J. Brazell, Site Security Manager
G. Bugg, Acting Manager, Radiological Control and Chemistry
D. Burrell, Design Engineering Manager
R. Coleman, Acting Radiological Control Manager
C. Crane, Site Vice President, Browns Ferry
R. Cutsinger, Chief Engineer - Corporate
J. Johnson, Site Quality Assurance Manager
R. Jones, Operations Manager
S. Kane, Licensing Supervisor
G. Little, Operations Superintendent
R. Machon, Former Site Vice President, Browns Ferry
G. Pierce, System Engineering Manager
E. Preston, Former Plant Manager, Browns Ferry
T. Shriver, Nuclear Assurance and Licensing Manager
K. Singer, Maintenance Manager
R. White, Operations Supervisor (Fire Protection)
H. Williams, Site Engineering Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Licensee Self-Assessments
IP 62700:	Maintenance Implementation
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92050:	Review of Quality Assurance for Extended Construction Delays
IP 92901:	Followup-Plant Operations
IP 92902:	Followup-Maintenance
IP 92903:	Followup-Engineering
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

Type	Item Number	Status	Description and Reference
IFI	50-259,260,296/97-01-01	Open	Resolution of UFSAR Discrepancies (E3.1)

Closed

Type	Item Number	Status	Description and Reference
LER	296/95-04	Closed	Unplanned ESF Actuation Following Transfer of 480V Shutdown Board 3A to Alternate Supply (O8.1)
IFI	259,260,296/96-10-04	Closed	EDG Material Condition Concerns (M4.2)
LER	296/95-07	Closed	Unplanned ESF Actuation Following Transfer of 480V RMOV Board 3B to Normal Power Supply (E8.1)
URI	259,260,296/96-04-08	Closed	FSAR Deficiencies (E8.2)
URI	259,260/93-11-02	Closed	Explanation of the Stress Intensity Shown in the Summary Stress Report for Reactor Vessels 1 and 2 (E8.4)
VIO	260/95-15-03	Closed	Failure to Implement the Corrective Action Program (E8.5)

VIO	296/95-57-01	Closed	Failure to Install Modifications in Accordance with Design Drawing Requirements (E8.7)

Discussed

Type	Item Number	Status	Description and Reference
IFI	296/96-04-04	Open	Failure of Feedwater Pump Discharge Check Valves (O1.1 and E8.3)
IFI	260/95-41-01	Open	EDG 1A Turbocharger Inspection (E8.6)