U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Facility:	Browns Ferry Nuclear Plant, Units 1, 2, & 3
Location:	Corner of Shaw and Browns Ferry Roads Athens, AL 35611
Dates:	June 22 - August 2, 1997
Inspectors:	L. Wert, Senior Resident Inspector J. Starefos, Resident Inspector C. Smith, Reactor Inspector (Sections E2.4, E2.5, and E8.5)
Approved by:	M. Lesser, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure 2

EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Units 1, 2, & 3
NRC Inspection Report 50-259/97-08, 50-260/97-08, 50-296/97-08

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection and inspection in the engineering area by a Region II reactor inspector.

Operations

Operations management promptly addressed a power supply problem associated with Anticipated Transient Without a Scram logic. Repairs were completed in a timely manner and with effective Operations controls. (Section 01.1)

Control room operators demonstrated an increased sensitivity to compensatory actions for inoperable equipment or instrumentation. The actions were conservative and completed at reasonable intervals. (Section 01.2)

Housekeeping deficiencies were identified in the Unit 3 shutdown board room chiller rooms and a ventilation tower. Overall conditions in the Unit 2 Reactor Building were improved. In the plant stack, conditions were satisfactory and the radiation monitoring system was aligned as required. (Section 02.1)

Monitoring of identified leakage problems did not identify improperly rigged catch devices or devices which were not properly sized to capture leakage. While the overall status of temporary leakage containment devices was acceptable, several of the devices were not effectively capturing the leakage. (Section 02.1)

Maintenance

The overall performance of the workers during Standby Gas Treatment System testing was good. Workers were attentive to details of the testing and good

procedural compliance was observed. The maintenance workers coordinated their efforts with Operations. The inspector identified that the surveillance instruction did not fully address orientation of the hot wire anemometer sensor probe during air flow measurements. (Section M1.1)

Engineering

The Unit 2 High Pressure Coolant Injection system was affected by steam admission valve leakage condensate entering a junction box through an unsealed conduit. Surveillance testing indicated that the system was capable of performing its safety function in the automatic mode. The valve steam leakage problems were known by the licensee and had existed prior to the most recent refueling outage. The licensee's detailed evaluation focused on effects of valve seat leakage. The potential effects due to external leakage were not as fully evaluated. The licensee's actions, including questioning of system performance during the surveillance testing, troubleshooting and immediate repair activities, and planned future corrective actions were good. (Non-Cited Violation 50-260,296/97-07-03, Failure to Identify Water Intrusion Into High Pressure Coolant Injection System Junction Box, Section E2.1)

The inspectors identified that two steam packing exhauster line stack isolation dampers had been positioned differently than configuration control drawings for approximately one year to address an equipment performance issue. The inspectors did not identify any immediate safety concerns with the equipment aligned in accordance with the engineer's instructions and the caution tag. However, actions had not been initiated to address permanent resolution of the problem. (Section E2.2)

Weaknesses in the licensee's lubrication oil analysis program permitted the incorrect type of lubricating oil to be added to a second EDG several months after it had been installed in a different EDG. (Unresolved Item 50-260/97-08-02, Incorrect Oil Used in Two EDGs, Section E2.3)

An error in the Materials/Procurement processes resulted in workers procuring the incorrect oil for addition to the EDGs. Similar examples of procurement weaknesses have been identified previously. The licensee has initiated an extensive Materials Upgrade Project to address the issues. (Inspection Followup Item 50-260,296/97-08-05, Materials Upgrade Project, Section E2.3)

The licensee's design control program was being implemented in accordance with the requirements of ANSI N45.2.11-1974. (Section E2.4)

One violation was identified for failing to perform a 10 CFR 50.59 Safety Evaluation for a change to the FSAR that permitted a new system alignment that previously had been prohibited by the licensing basis. The deficiency apparently involved misapplication of "S" DCN which cannot be used for making system alignment changes. Secondary cause was complex design control process which uses numerous alphabet designated DCNs with unique administrative controls. (Violation 50-260/97-08-01, Failure to perform a 10 CFR 50.59 Safety Evaluation for New System Alignment, Section E2.4)

Technical Operability Evaluations were technically adequate. (Section E2.5)

Procurement issues involving Ellis and Watts (Shutdown Board Room Chillers) commercial dedication plans were adequately dispositioned for release of material. (Section E8.5)

The inspector concluded that the licensee's overall investigative and corrective actions regarding a series of Emergency Core Cooling System inverter failures were effective. The inverters continue to be monitored by the licensee as an a(1) system in accordance with the maintenance rule. The failures and corrective actions were well documented in the licensee's corrective action system. (Section E8.1)

Plant Support

During observation of a compensatory raw cooling water sampling activity required by the Offsite Dose Calculation Manual, two deficiencies were noted. The worker did not fully comply with the sampling procedure. The safety significance of the specific deficiencies was small since the overall intent of the steps was met. Additionally, the Chemistry Shift Supervisor indicated to the inspector that he was not aware of how the Lower Limit of Detection acceptance criteria was met. (Non-Cited Violation 259/97-08-04, Failure to Follow Chemistry Sampling Procedure, Section R4.1)

Report Details

Summary of Plant Status

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

Units 2 and 3 operated at or near full power with the exception of routine testing and scheduled maintenance downpowers.

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 most of the areas inspected. Section E8.2 describes a minor UFSAR discrepancy identified during the reviews. NRC review also identified that a safety assessment contained an incorrect statement. (Section E2.1).

I. Operations

O1 Conduct of Operations

O1.1 Unit 3 Anticipated Transient Without a Scram (ATWS) Logic Power Supply Problem

a. Inspection Scope (71707, 62707)

The inspector reviewed actions taken when Unit 3 experienced a loss of power to anticipated transient without a scram (ATWS) B logic power. The inspector reviewed the licensee's plan to repair the breaker, observed some of the repair activities, reviewed the clearance, and observed a portion of the equipment restoration.

b. Observations and Findings

On June 21, 1997, Unit 3 experienced a loss of power to anticipated transient without a scram (ATWS) B logic power. The licensee determined that the power interruption was caused by a contact problem with normal supply breaker 3-FUDS-248-3EBQ on the 3EB 250V DC distribution panel. The licensee cycled the breaker several times and verified that power was restored to the ATWS B logic panel. Several hours later, the licensee transferred ATWS B logic power to the alternate power supply. The licensee performed shiftly voltage readings on the normal supply to

ATWS B. The inspectors considered this to be an example of increased sensitivity to compensatory actions by Operations as discussed in Section O1.2.

On June 26, 1997, the licensee removed the 3EB 250V DC distribution panel from service to replace the 3-FUDS-248-3EBQ breaker. The licensee removed a spare breaker from another part of the distribution panel and replaced the 3-FUDS-248-3EBQ breaker in accordance with work order 97-006508-000. To remove the 3EB 250V DC distribution panel from service for the breaker replacement, the licensee transferred the 3EB 4160V shutdown board control power to its alternate supply, disconnected the 3EB battery from the panel, and disconnected the 3EB battery charger from the panel. The ATWS B logic power was already transferred to its alternate power supply. Technical Specification (TS) 3.9.B.6 requires the licensee to notify the NRC within 24 hours of the time that the 250V shutdown board 3EB battery and/or its associated battery board is found to be inoperable for any reason; continued reactor operation is permissible during the succeeding seven days. The licensee reported the removal of the 250V shutdown board 3EB and the distribution panel from service as required by TS 3.9.B.6.

The inspector reviewed clearance 3-97-0507, verified that tags were hung on equipment in the field, and that the equipment was in its designated clearance position. No concerns were identified. Following the breaker replacement, the licensee identified a problem with the physical interlocks which keep the panel door closed when the breaker is closed. During troubleshooting work, the inspector noted that a number of the breakers within the clearance boundary were manipulated. The inspector discussed this with the tagging SRO and a component verification sheet was prepared for designated breakers on the panel.

c. <u>Conclusions</u>

Operations management promptly informed the resident inspectors of the problem with the normal supply breaker and their plan to effect repairs. The repairs were completed in a timely manner and with effective Operations controls.

01.2 General Observations

a. Scope (61726, 71707)

One of the inspectors observed Assistant Unit Operators (AUOs) in the diesel generator room during surveillance instruction (SI) 3-SI-4.9.A.1.a(3B), Diesel Generator 3B Monthly Operability Test.

The inspectors reviewed the compensatory actions initiated by the control room personnel for inoperable instrumentation or equipment.

The inspectors verified that proper actions were completed when important electrical equipment was placed in an alternate alignment.

b. Observations and Findings

On July 20, 1997, the inspector observed performance of surveillance instruction 3-SI-4.9.A.1.a(3B), Diesel Generator 3B Monthly Operability Test, Revision 28. The inspector attended the pre-job briefing prior to the test and noted that the workers were told to ensure that they were on the right component. Discussion with the AUO regarding draining condensate from the fuel oil day tank indicated that the AUO was knowledgeable of how to properly perform the activity. The AUO demonstrated the technique to verify that the control cabinet fan was operating. In general, observed AUO performance was good.

The inspector noted that several steps of a section of the procedure were performed before the preceding step was signed off. The inspector observed that the procedure steps were being completed in order and that the oversight was administrative. As discussed in Inspection Report 50-259,260,296/97-07, similar practices have been previously noted and licensee management is reviewing the guidance currently set forth in SSP-2.1, Site Procedures Program for signing off steps of continuous use procedures.

Over the last several months, the inspectors have noted an increased sensitivity toward implementing compensatory actions for plant equipment problems. Examples included monitoring of 3B drywell control air compressor oil level due to 3A drywell control air compressor being out of service, generator PCB 234 cooling water conductivity monitored due to annunciator disabled, south emergency equipment cooling water header pressure monitored due to a pressure transmitter being inoperable, and Unit 2 recombiner room temperature monitored due to annunciator alarm

disabled. In general, the control room operators exhibited more sensitivity towards compensatory actions than was observed during previous inspections.

. The inspectors reviewed an evolution in which control room operators were required to calculate transformer loading and observe unusual restrictions in an off-normal electrical switchgear alignment. A related potential concern regarding this is discussed in Section E2.5 of this report. On July 24, 1997, the 2B 480 V Shutdown Board was placed on its "alternate" supply to support transformer work. This invoked several special operating restrictions and necessitated calculation of loading by the operators. The inspectors reviewed the applicable plant drawings and instructions to determine the appropriate actions. The inspector verified that the restrictions had been met and that the operators performed the calculations correctly. Two SROs in the Unit 2 control room were able to explain the loading calculations and had performed them correctly. The inspectors concluded that the calculations were not unreasonably difficult for the operators to perform. The work and the methods to meet the alignment restrictions were planned through Maintenance and Engineering and set forth in a detailed "fragnet" before the board alignment was revised.

c. Conclusions

General observations during the report period were positive. Control room operators demonstrated an increased sensitivity to compensatory actions when equipment or instruments were inoperable. Operators successfully performed calculations to meet special operating restrictions due to an off-normal electrical switch gear alignment.

02 Operational Status of Facilities and Equipment

02.1 Plant and Equipment Walkdowns

a. Inspection Scope (71707)

In addition to routine plant tours, the inspectors reviewed installed temporary leakage containment devices and performed a detailed tour of the plant stack. The stack tour specifically focused on dilution fans/dampers and the stack radiation monitoring system.

b. Observations and Findings

On July 23, the inspectors walked down the plant stack, focusing on operability of the dilution fans/dampers and the stack effluent radiation monitoring equipment.

Valves were positioned as described on controlled drawings with one exception. Section E2.1 of this report describes review of a steam packing exhauster bypass line damper which had been caution tagged shut since August 1996. Several valves were locked in position which the Mechanical Control drawing did not specifically require to be locked. The inspectors confirmed that the valves were appropriately listed in the Operating Instructions. Although some areas had large quantities of insects present, overall housekeeping conditions in the stack were acceptable. Material was properly stored with no excessive accumulation of equipment. The radiation monitoring system was aligned as required and appeared to be functioning properly.

The inspector noted that valve 2-65-513 (isolation valve in dilution line to Standby Gas Treatment system header) was incorrectly listed on drawing 2-47E610-66-1 R024 as 3-65-513. The licensee initiated a Problem Evaluation Report (PER) to address this issue.

Early in the inspection period, the inspector noted poor housekeeping conditions in the Unit 3 shutdown board chiller rooms. The conditions were corrected later in the inspection report period but the floor drains in the rooms remained clogged. The inspectors also noted a pile of high efficiency particulate filters in one of the vent towers above the control building. The filters were subsequently removed from the tower.

On July 16, 1997, one of the inspectors examined a sampling of identified leaks and leakage containment devices throughout the plant. Condensation from an identified steam packing leak on the Unit 2 High Pressure Coolant Injection (HPCI) system leaked into a junction box and affected the HPCI control system (Section E2.1). At the time, the licensee was tracking 27 non-contaminated and 34 contaminated temporary leakage containment devices. The inspector reviewed 14 of the non-contaminated leakage devices. Only one deficiency was noted. Device number 25, associated with a recirculation pump oil system leak, was not capturing all of the leaking oil and oil was running down adjacent structural material. The inspector reviewed 16 of the 34 leakage containment devices for contaminated systems. Problems were noted with

five of the temporary devices. Several devices were not effectively capturing the leakage due to undersized devices or not properly rigged devices. Plant management was informed of the observations. Subsequently, the inspectors noted that the observed problems had been corrected. The licensee tracks temporary leakage containment devices and an updated list is reviewed each week at the Plan of the Day meeting. The licensee does not have a formal process which would ensure specific regular or periodic review of the installed devices. The licensee relies on routine Operations tours or system engineer observations to monitor identified leakage problems.

c. Conclusions

Housekeeping deficiencies were identified in the Unit 3 shutdown board room chiller rooms and a vent tower. With the exception of chiller room floor drain blockage, those issues were corrected during the inspection period. In the plant stack, material was properly stored and there was not an excessive quantity of stored equipment. The radiation monitoring system was aligned as required and appeared to be functioning properly.

Licensee monitoring of identified leakage problems did not identify improperly rigged catch devices or devices which were not properly sized to capture leakage. While the overall status of temporary leakage containment devices was acceptable, several of the devices were not effectively capturing the leakage.

08 Miscellaneous Operations Issues (92901)

08.1 (Closed) Licensee Event Report (LER) 296/95-008, Core Thermal Power Exceeded Operating License's Maximum Power Level Due to a Drifting Temperature Transmitter. Violation 296/96-01-01, Core Thermal Power Above Licensed Condition Maximum, also addressed this issue. The licensee's corrective actions were reviewed and the violation was closed in Inspection Report (IR) 96-04. The IR noted that the licensee completed several corrective actions which were not listed in the response to the Notice of Violation. The inspectors continue to observe that the Unit Operators are informing the Unit Senior Reactor Operator of recirculation flow changes. The LER is closed.

08.2 (Closed) Violation 296/95-64-01, Fire Protection Program Equipment Inoperable Without Compensatory Actions. This violation addressed two examples in which required compensatory actions were not initiated for inoperable fire protection program equipment. An improper clearance

rendered a reactor building preaction sprinkler valve inoperable and an inoperable battery charger switch was not recognized as fire protection equipment. The licensee has strengthened the processes used to develop and review clearances since this event and no similar incidents have occurred. The second deficiency occurred due to a vendor wiring error in the control panel for the battery charger. Since 1986, the licensee has had procedural requirements for wiring verification of new vendor wired electrical equipment. No additional examples of such problems have been noted. NRC checks of fire protection program compensatory measures have not identified any problems in recent months.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Standby Gas Treatment (SBGT) System Testing

a. Inspection Scope (61726)

Utilizing the guidance of Inspection Procedure 61726, the inspector observed major portions of five surveillance tests conducted on the "C" train of SBGT.

0-SI-4.7.B.1.B-3	"C" SBGT Humidity Control Heater Test
0-SI-4.7.B.3-3	"C" SBGT Flow Distribution Test
0-SI-4.7.B.1.A-3	"C" SBGT Filter Pressure Drop Test
0-SI-4.7.B.7	"C" SBGT Flow Rate Test
0-SI-4.7.B.8	"C" SBGT Housing Door Gasket Seal

b. Observations and Findings

During the period of July 9-11, 1997, the inspector observed testing of the SBGT system as required by technical specifications (TS). In preparation, the inspector reviewed controlled drawings and UFSAR descriptions of the system, walked down portions of the SBGT system, and reviewed operating and testing procedures.

The inspector observed that the humidity heater control testing was well controlled, with close utilization of the procedure. The inspector observed that torquing of the dyoctlphosphate test port flanges was performed properly with Quality Control involvement as required by the procedure.

The inspector noted that mechanical maintenance workers coordinated with Operations to obtain permission to begin testing and ensure that the prerequisites were met for the other four tests. The workers were also diligent regarding signing off the initial steps in the procedure as they were completed. The workers had marked the pitot tube and the hot wire anemometer tube with tape to expedite traverse point measurements.

During the SBGT flow rate test, two 20 point pitot tube traverses were obtained from SBGT piping located in the plant stack. The inspector observed that the workers attempted to be accurate and consistent regarding manometer data. The inspector recorded manometer readings and performed the calculations of SBGT train flow independent of the workers. The inspector obtained flowrate values very close to the values the workers obtained and well within the acceptance criteria.

The uniformity of air distribution across the High Efficiency Particulate Air (HEPA) filters and charcoal adsorbers is required to be checked by TS 4.7.B.1.c. Procedure 0-SI-4.7.B.3-3, "C" SBGT Flow Distribution Test, is used to perform this testing. A hot wire anemometer is utilized to obtain a nine point velocity profile on the upstream HEPA filter. During the testing, the inspector observed that rotation of the probe with respect to air flow affected the readings obtained. At one point, an initial reading was lower than the expected value. After obtaining the other two points in that column, the workers obtained another reading at the first point which was close to the other two point values. By referring to a piece of tape on the probe tube extension, the inspector noted that the orientation of the tube had been changed between the readings. At the inspector's request, the workers rotated the probe ninety degrees at another point and it was confirmed that the orientation of the probe affected the readings. Although some discussion was held on the orientation of the probe, the workers did not indicate that they were aware of the significance of probe orientation. Subsequently, the inspector reviewed the instruction manual supplied by the instrument vendor. The manual stated that a red dot painted on the end of the probe was to be toward the air flow to obtain valid readings. The inspector confirmed that there was a red dot on the probe as specified. Discussions with maintenance training personnel indicated that the probe orientation was briefly addressed during training sessions with the workers. The inspector noted that the probe only extends to 21 inches and the workers have to attach the probe to an extension tube to extend it far enough into the train. This increases the difficulty in ensuring that the probe is oriented properly. These observations were reported to plant management.

The licensee subsequently concluded that the performed SI was acceptable. However, the test procedure was revised to require that the maximum indicated flowrate (as the probe is rotated) be recorded at each measurement point. The inspector concluded that this would provide a more accurate assessment of flow distribution within the train.

Additionally, the plant manager informed the inspector that his investigation indicated that the workers were aware of the significance of probe orientation but had apparently not communicated their knowledge to the inspector. The inspectors concluded that the licensee's revision to the procedure adequately addressed the issue and strengthened instructions to the workers regarding air flow measurements. The inspectors did not identify reasonable conditions where improper probe orientation would have failed to identify inadequate air flows.

The SBGT Filter Drop Test and Housing Door Gasket Seal Test were completed satisfactorily and results were within acceptance criteria.

During reviews of the SBGT system, the inspector identified that the Unit 3 control room mimic had manual bypass decay heat line damper DMP-65-02 labeled as DMP-65-21. This was reported to Operations management. The inspector subsequently verified that the control room mimic was corrected.

c. Conclusions

The overall performance of the workers during the testing was good. Workers were attentive to details of the testing and good procedural compliance was observed. The maintenance workers coordinated their efforts with Operations. The inspector identified that the surveillance instruction did not fully address orientation of the hot wire anemometer sensor probe during air flow measurements. One minor deficiency involving a control room mimic display was noted.

M1.2 Unit 2 Scram Discharge Volume Functional Testing

a. Inspection Scope (61726)

The inspector observed the performance of Surveillance Instruction 2-SI-4.1.A-8(F), RPS High Water Level in Scram Discharge Tank Functional Test 2-LS-85-45E and 2-LS-85-45F, Revision 12.

b. Observations and Findings

On July 8, 1997, the inspector observed the performance of Surveillance Instruction 2-SI-4.1.A-8(F), RPS High Water Level in Scram Discharge Tank Functional Test 2-LS-85-45E and 2-LS-85-45F, Revision 12. The inspector observed portions of the SI from the cage area around the east scram discharge tanks, from the control room, and from the Unit 2 auxiliary instrument room. The individuals performing valve manipulations in the field exercised clear communications and verified the correct components before manipulation. Second party verification and independent verification was adequate.

During the performance of the testing, the inspector noted that the individuals performing the test were careful to control a test valve by attaching it to the area cage. During previous testing, water had leaked by the valve causing a half-scram (IR 97-01, Section M4.1). In addition, the inspector noted that the licensee enhanced the SI procedure by adding a step to close the demineralized water source connection valve which provides a second isolation between the manometer and the water supply.

M8 Miscellaneous Maintenance Issues (62707, 92902)

M8.1 (Closed) Violation 260/96-03-01, Failure to Follow Procedures During Core Spray Valve Maintenance. NRC inspectors identified that maintenance workers were not signing off completion of steps as the work was completed. Plant management has continued to emphasize that procedural steps are to be completed and, when required, signed as the steps are completed. Recently, the inspectors have noted that "continuous use" procedures are being revised to support step completion documentation at appropriate locations in the procedure. The inspectors have noted overall improvement in maintenance workers signing off prerequisites or major steps as they are completed. However, some procedures are not written in a manner to support rigid step-by-step signoffs. Section M1.1 of Inspection Report 97-07 describes NRC observation of Common Accident Signal Testing in which workers completed small groups of steps before stopping to sign steps. The steps were performed correctly and in sequence. The inspectors have observed plant management discuss the issue of completion signoffs in Management Review Committee meetings. Procedures are being revised as enhancement areas are identified. Section M1.1 of this report describes testing observations in which it was noted that the workers were sensitive to sequential step completion. The violation is closed.

M8.2 (Closed) Violation 260/96-04-01. Licensee Identified Appendix R Deficiencies. This violation addressed several Appendix R issues identified during extensive re-analysis of the Unit 2 safe shutdown program. The Notice of Violation stated that no response to the violation was required since the licensee had adequately addressed the issues in Licensee Event Report (LER) 260/96-001. Revision 1 of the LER was closed in IR 96-08. The licensee thoroughly reviewed each of the deficiencies and concluded that no consistent trend or methodology problems were involved. The inspector reviewed documentation which indicated that modification F39514A had been completed which re-routed several instrumentation cables to correct the problems. The other corrective actions in the LER were completed as well. The violation is closed.

M8.3 (Closed) Licensee Event Report (LER) 260/96-001-00. 10 CFR Part 50 Appendix R Noncompliance Results in the Plant Being Outside Its Design Basis and Being in a Condition Not Covered by Plant Operating Instructions. Section M8.2 describes review of a violation which addressed the issues in the LER. Revision 1 of the LER was closed in IR 96-08. Due to an administrative oversight, Revision 0 was not closed at that time. The LER is closed.

M8.4 (Closed) Unresolved Item (URI) 50-259,260,296/96-13-02. Toolpouch Issues. This URI contained two central issues. The first issue was adequacy of the toolpouch maintenance process for work on the emergency diesel generators (EDGs). The second issue involved weaknesses in the procurement processes which could have allowed improper material (glycol) to be added to the EDGs.

The licensee completed an evaluation of whether the Toolpouch Maintenance process was appropriate for adding demineralized water to the emergency diesel generators cooling systems. The licensee determined that the toolpouch criteria and examples, described in site standard practice (SSP) procedure SSP-6.2 (Maintenance Management System) Appendix T (Implementing Toolpouch Maintenance), could not be used effectively to determine toolpouch maintenance items. Problem Evaluation Report (PER) BFPER961761 addressed this issue with an update to procedure SSP-6.2 Appendix T. Craft supervisors, foremen, and

maintenance planners were briefed on the revised procedure appendix. The inspector reviewed SSP-6.2 Appendix T, Revision 26, and concluded that the procedure would currently not allow demineralized water addition to the emergency diesel generators cooling systems using the Toolpouch Maintenance Process.

Due to another problem that occurred involving the EDG coolant expansion tank, the licensee developed an operations plant information posting (PIP-97-179) and installed it at each diesel informing personnel to contact chemistry for any additions, sampling, or chemistry concerns.

Based upon the licensee's actions to clarify the procedure for Toolpouch Maintenance, to inform responsible individuals of the changes, and installing Plant Information Postings at each diesel, the inspector concluded that this portion of the Unresolved Item is closed. No violation of regulatory requirements was identified.

The second part of the URI identified the potential for ethylene glycol to be issued by TVA Power Stores for use in the Emergency Diesel Generators (EDGs) despite the fact that Site Standard Practice SSP-13.1, Chemistry Program, does not consider ethylene glycol as acceptable for use in the EDGs. This portion of Unresolved Item 50-259,260,296/96-13-02 will be addressed by Inspection Followup Item (IFI) 50-260,296/97-08-05, Materials Upgrade Project. This IFI is addressed in more detail in Section E2.2 of this report. Unresolved Item 50-259,260,296/96-13-02, Toolpouch Issues is closed.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Water in Junction Box Results in High Pressure Coolant Injection System Inoperability

a. Scope (62707, 71707, 37551)

Condensation from a steam leak on the Unit 2 High Pressure Coolant Injection (HPCI) system steam admission valve entered an electrical junction box and affected the HPCI system. The inspectors monitored the licensee's efforts to troubleshoot and correct the problem. The inspectors reviewed the licensee's controls regarding junction box

sealing. The inspectors reviewed electrical wiring and HPCI control system drawings as well as test data to verify the impact of the water intrusion on the HPCI system.

b. Observations and Findings

On July 11, 1997, during the performance of surveillance instruction (SI) 2-SI-4.5.E.1.d, HPCI [High Pressure Coolant Injection] Flow Rate Test at Normal RPV [Reactor Pressure Vessel] Pressure, the HPCI system did not meet the SI requirements while the system was in manual mode. The testing indicated an acceptable flow (5050 gpm), at a discharge pressure capable of vessel injection (1210 psig). The Unit 2 HPCI system was declared inoperable for troubleshooting and corrective actions. The licensee reported the condition to the NRC. The inspectors observed portions of the troubleshooting activities and monitored the licensee's investigation into the cause of the problem.

Initial troubleshooting identified a problem with the speed indicator card in the EGM portion of the turbine governor. The licensee replaced the speed indicator card and reperformed the surveillance test. The testing indicated similar results with a small improvement in indicated performance. Erratic indications were noted when the speed control potentiometer on the HPCI speed controller was touched, indicating ground problems. The licensee was concerned that the ground on the speed controller may have damaged the speed indicator card, so it was replaced a second time. Additional troubleshooting identified that the output of the speed control potentiometer on the HPCI speed controller was erratic. After correcting the apparent problems, the licensee ran the SI again and determined that the symptoms still existed. Further troubleshooting identified that a ground existed in the circuit which was traced to junction box 8272 on the HPCI skid.

Additional inspection indicated that water was leaking into junction box 8272. This is a junction box located adjacent to the HPCI turbine skid which contains a terminal board and electrical connections. On July 14, 1997, one of the inspectors observed the inspection and repairs to the junction box in accordance with Work Order 97-007072-000.

The inspector observed that water was entering the junction box and essentially all the terminal points on a large terminal strip inside the box were wet. Corrosion was evident on many of the connections. The inspector traced the source of the water and determined that it was from a packing leak on the 73-16 valve (HPCI steam admission valve).

Condensed steam had accumulated in insulation on piping, then dripped out the other side of the insulation on a nearby pipe elbow and finally dripped on the top of the junction box. The water entered the box through two unsealed conduit connections on the top of the box and ran down the terminal strip. The inspector noted that the leakage into the box was difficult to observe. There was not a visible puddle on top of the box and the path of condensate from the 73-16 steam leakage to the box was torturous (the steam was not simply condensing on a nearby surface and dropping into the box).

The terminal strip was replaced, the conduit connections were sealed with an approved sealant material, and the 73-16 steam leak condensation was routed to a drain. The inspector observed that the workers were careful about component verification prior to beginning work and utilized procedures to track configuration as wires were lifted and reconnected.

The 73-16 internal leakage issues had been identified on both Browns Ferry units as early as 1994. Engineering has been pursuing corrective actions, including a modification which would replace the valves, with an improved design in a vertical orientation. A management decision was made to not replace the valve during the last refueling outage. Technical Operability Evaluation (TOE) 2-94-073-9014, Unit 2 HPCI Steam Admission Valve Leakage Problems, had been written to address the leakage and related issues. The TOE has been updated several times since the original version. The current revision, Revision 4, is a highly detailed assessment of the degraded condition. The Senior Resident Inspector had reviewed the TOE and discussed the issues with the HPCI system engineer previously. The TOE thoroughly addressed issues associated with leakage past the seat of the valve. The TOE addressed external leakage impacts briefly from the perspective of room temperature.

The inspectors reviewed the licensee's controls regarding sealing of junction boxes and concluded that there are two basic methods for controlling the sealing of the boxes:

- Drawing 0-45B891-1, Conduits and Grounding Waterproofing and Sealing, Details of Electrical Equipment, provides guidance regarding sealing of junction boxes. Note 2 of the drawing states: "Seal conduits and boxes in the reactor building, control bay, pumping station, and diesel generator buildings in accordance with notes 3 thru 9. See Drawing 0-45E491-31 for list of junction

boxes that are required to be sealed." Junction box 8272 is not listed on drawing 0-45E491-31. Note 1 on Drawing 0-45E491-31 states: "Listed are the Unit 1, 2 and 3 and common area enclosures which contain electrical components that require moisture protection. Seal these boxes according to requirements on Drawing 45E891-1." Terminal or connection boards are not normally considered as components that would require sealing. The junction boxes that are required to be sealed contain environmental qualification sensitive electrical equipment.

- Attachment 5 of Procedure EII-0-000-TCC106, Troubleshooting and Configuration Control of Electrical Equipment contains guidance for resealing of conduit boxes opened during performance of the troubleshooting procedure. Page 2 of the attachment contains specific guidance for junction box sealing and drainage hole verification. Page 1 contains a note "per drawing 45B891." As described above, since JB 8272 is not listed on the drawing, these instructions would not result in the JB being sealed after work was completed in the box.

The inspector had observed that it is a common work practice at Browns Ferry to thoroughly seal junction boxes after work activities are completed, if the box was found sealed, including some boxes not listed on 45E491-31. In most cases, similar boxes have conduits with watertight threaded conduit boss hubs or the connections are sealed with an approved sealant. The inspectors noted that the conduit connections on the identical junction box on Unit 3 HPCI appeared to be sealed but no drainage hole is present.

The inspector reviewed the history associated with the licensee's processes for junction box and conduit sealing. In August 1987, water was introduced into the scram discharge instrument volume instrumentation through an unsealed conduit after an inadvertent fire suppression system actuation. A Notice of Violation was issued in Inspection Report 87-33 on this issue. Condition Adverse to Quality Report (CAQR) BFN 870913 was initiated. Initially, the licensee's planned corrective actions included sealing of all junction boxes in the intake structure, control bay, reactor building, and diesel generator building. In an October 17, 1991, letter to the NRC, TVA revised the commitment. An evaluation of plant areas subject to moisture intrusion and required to support Unit 2 operations was performed. TVA identified areas where conduit and junction boxes could be subjected to condensation from moderate and high energy line breaks and from open

head fixed water spray fire protection systems. The list of junction boxes to be sealed was reduced. The violation was closed out in IR 91-16.

The inspectors reviewed plant instructions, design specifications, and drawings regarding the HPCI room junction boxes. The inspectors concluded that the boxes are not required to be included on the list of junction boxes to be sealed:

- Drawings 47W225-103 and -104 address the harsh environmental data for the Unit 2 HPCI room. The High Energy Line Break (HELB) profiles indicate that the HPCI room is not considered a harsh environment for any HELB scenarios except for a line break in the HPCI room itself. Since a HELB in the HPCI room would involve the HPCI steam piping, the HPCI system is not expected to perform in a harsh environment.

- The fire protection systems in the Unit 2 and Unit 3 HPCI rooms were converted to closed head systems prior to each unit restart. In addition, to actuate the local spray device, a heat detector must actuate a preaction valve to initiate water spray to the nozzles. As such, HPCI room junction boxes would no longer be considered as vulnerable to moisture intrusion from inadvertent fire suppression system actuation.

The inspector's review also identified that Inspection Followup Item 84-41-04 indicated that the licensee had previously identified a need to relocate the HPCI EGM control box. Due to high moisture and temperatures, the licensee implemented ECN P3184 which moved the controls from adjacent to the HPCI turbine (in JB 8272) to a location on a HPCI room wall. (Earlier work by General Electric had preliminarily indicated that the HPCI room would be a harsh environment, but this was later revised). The inspectors reviewed portions of the ECN package and did not identify any requirements to seal JB 8272 during the work.

In LER 260/97-003-00, the licensee stated that the HPCI system could have performed its function (prior to being removed from service for repairs). The inspectors reviewed electrical drawings and test data and concluded that the information supported a conclusion that the HPCI system was operable. The observed problems were due to the water affecting the speed indication/control circuit which did not affect HPCI as far as automatic startup and injection. The inspectors noted that the water and corroded terminations could have affected automatic

injection, had this condition persisted, since some of the wetted terminations are associated with the EGM control circuitry. 10 CFR 50, Appendix B, Criterion XVI, requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In this case, Unit 2 High Pressure Coolant Injection system controls were affected due to steam admission valve leakage condensate entering a junction box through unsealed conduit. The valve steam leakage problems were known by the licensee and had existed prior to the most recent refueling outage. The licensee's detailed evaluation focused on effects of valve seat leakage and potential effects due to external leakage were not as fully evaluated. Although several factors made it difficult to see the leakage into the junction box, the degraded condition was not identified until after HPCI was affected. Conditions inside the junction box indicated that water had been entering the box for several months prior to identification.

Corrective actions include:

- HPCI was declared inoperable and after some troubleshooting, traced the cause to water entering the box. The damaged terminal strip was replaced, the box was sealed. Leakage containment around the 73-16 valve was improved.

- All installed "leakage containment devices" (the devices are numbered and tracked) were examined to ensure that no other similar problems existed.

- Walkdowns of HPCI, RCIC, and feedwater pump rooms where steam condensate could leak on junction boxes will be performed. Conduit terminations would be sealed on those deemed to be unacceptable.

- Training modules will be developed to address this event and management expectations on reviewing affects of plant leaks and the reporting of such leaks.

- A Site Bulletin will be issued to heighten awareness of plant personnel to this event.

The inspectors concluded that the licensee's corrective actions are adequate. The condition was identified by the licensee as a result of questioning during the performance of surveillance testing. Although available information indicates that the HPCI system could have performed its intended safety function during the testing, the condition was adverse to quality and was not promptly identified. This licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of NRC Enforcement Policy. (NCV 50-260/97-07-01, Failure to Identify Water Intrusion Into High Pressure Coolant Injection System Junction Box).

c. Conclusions

The Unit 2 High Pressure Coolant Injection system was affected by steam admission valve leakage condensate entering a junction box through unsealed conduit penetrations. The valve steam leakage problems were known by the licensee and had existed prior to the most recent refueling outage. The licensee's detailed evaluation focused on effects of valve seat leakage and potential effects due to external leakage were not as fully evaluated.

The inspectors concluded that three key issues played a role in the HPCI control system being affected prior to identification of the problem. Effects of longterm external valve leakage were not evaluated in a sufficiently detailed manner to identify the leakage into the junction box. Identified long-standing valve leakage conditions were not periodically evaluated by means other than routine rounds. Some electrical junction boxes adjacent to steam operated equipment are not sealed against moisture intrusion.

The licensee's actions, including questioning of system performance during the surveillance testing, troubleshooting and immediate repair activities, and planned future corrective actions were good.

E2.2 Steam Packing Exhauster Bypass Line Dampers Positioned by Caution Tag for Extended Time Period

a. Inspection Scope (37551)

During a tour of the plant stack on July 23, 1997, (Section O1.2) the inspectors noted that caution tag 0-96-0355-1 was present on damper 0-DMP-66-953A. The tag had been installed in August 1996 and stated that the damper was to be shut. Since the controlled drawings indicated that

the damper was to be open and the tag had been in place for almost a year, the inspectors reviewed the damper position and caution tag issues more closely.

b. Observations and Findings

Caution Tag 0-96-355-1 stated that 0-DMP-66-953A was to remain shut. Two isolation dampers (0-DMP-66-953A and 953B) are located in a pipe from the steam packing exhaust to the stack [Steam Packing Exhauster (SPE) bypass line]. Two backdraft dampers are located between the isolation dampers. There is an additional set of isolation dampers and backdraft dampers in parallel with this line. The inspectors noted that Configuration Control Drawings 2-47E809-2 (Revision 21) and 2-47E610-66-1 indicated that the bypass isolation dampers were to be open. Note 11 on 2-47E809-2 stated that air flow was required to open the backdraft dampers to prevent condensation from forming water on the backdraft dampers. After some review, the inspectors determined that Design Change Notice (DCN) T35568A had been implemented in September 1995 which had revised the 953A and 953B normal positions to "open." The DCN stated that the isolation dampers were to remain open to prevent moisture accumulation on the backdraft dampers. In the past, condensation of the SPE steam had accumulated above the dampers and degraded the dampers.

The caution order 0-96-0355 referenced PER 960695 and Technical Operability Evaluation (TOE) 0-96-66-0695 which addressed the problems with the backdraft dampers. The TOE specifically addressed acceptability of the condition at the time of exceeding 10 standard cubic feet per minute leakage on the backdraft dampers. The TOE was closed in September 1996 after work was performed on the dampers and the leakage rate was reduced. Apparently, the caution tag was subsequently issued to isolate the SPE bypass, forcing flow through the main SPE discharge line, to address low flow conditions in the lines. The inspectors did not find any open document directly relating to permanent resolution of the problem which resulted in the caution tag. However, Work Order 97-000712-000 was open which notes that the dampers are shut by the caution order and requests an inspection of the backdraft dampers. The inspectors noted that the dampers had remained positioned differently than configuration control drawings for approximately one year.

The licensee subsequently completed a 10CFR50.59 screening review and safety assessment in accordance with Site Standard Practice SSP-9.4 on July 24, 1997. The assessment concluded that the alignment was acceptable from a nuclear safety viewpoint and did not represent a unreviewed safety question. Work Order 97-000712-000 was rescheduled to an earlier date to perform inspections of the backdraft dampers.

During a subsequent review, the inspectors noted that the safety assessment included an incorrect statement. The assessment stated that the situation did not represent a change to the facility as described in the UFSAR. This resulted in a safety evaluation not being performed at the time the assessment was completed. One of the inspectors identified that the drawing depicting damper configuration and note 11 (described above) was included in the FSAR. On August 13, 1997, a safety evaluation was completed which satisfactorily addressed the condition.

c. Conclusions

The inspectors identified that the steam packing exhauster line stack isolation dampers had been positioned differently than configuration control drawings for approximately one year to address an equipment performance issue. There is not a specific regulatory requirement to have a completed safety assessment/evaluation for such a condition. The inspectors did not identify any safety concerns with the equipment aligned in accordance with the engineer's instructions and the caution tag. The inspectors concluded that the primary concern is that actions were not initiated to address permanent resolution of the problem.

E2.3 Emergency Diesel Generator Lube Oil Issues

a. Inspection Scope (37551, 93903)

The inspector reviewed the circumstances surrounding two instances of incorrect oil added to the Unit 1/2 EDGs.

b. Observations and Findings

The inspector determined that two separate aspects of this problem should be addressed. The first aspect dealt with the failure of the licensee to promptly identify that zinc additive oil had been put in the

2A EDG. This failure led to the incorrect oil also being put into the 2D EDG approximately four months later. The second aspect of the problem dealt with the procurement control deficiencies which permitted the incorrect oil to be used in both EDGs.

On February 1, 1997, Mechanical Maintenance (MM) added lubricating oil to the Unit 1/2A EDG in accordance with work order (WO) 97-001076-000. The WO documented work instructions in a step text format which directed MM to add oil to the EDG through the oil strainer box and referenced TVA Item Identification Code (TIIC) CAQ-060B. The inspector reviewed the archived copy of the Power Stores procurement form (Form 575) and verified that TIIC CAQ-060B was procured. One 55 gallon drum of oil was added to the 2A EDG. On July 2, 1997, MM added 55 gallons of oil (TIIC CAQ-060B) to the 2D EDG while performing WO 97-006843-000.

The licensee was informed of high zinc content in oil chemistry samples for the 2A EDG on July 9, 1997, when a preliminary copy of the chemistry report was faxed to the site from TVA Central Labs. The report included data from several lube oil samples for the 2A EDG. The following five samples, taken on the dates noted, identified that zinc exceeded the vendor limit of 10 ppm maximum:

03/06/97	148 ppm zinc
03/27/97	125 ppm zinc
05/10/97	170 ppm zinc
06/09/97	169 ppm zinc
06/19/97	166 ppm zinc

Subsequent testing on July 14, 1997, revealed that the zinc content in 2D EDG was 147 ppm.

The concern with zinc in the lube oil is that oil containing zinc additives could, over a period of time, result in damage to the EDG bearings which contain silver. Unit 1/2 EDG A/B/C/D oil samples taken July 14, 1997, indicated <1 ppm silver, which indicated that no significant degradation had occurred. The licensee determined that TIIC CAQ-060B was not procured as a zinc free oil.

On July 14, 1997, the licensee drained the lube oil from the "A" EDG and installed new filters and oil using work order (WO) 97-007028-000. Preliminary test results from the oil sample taken on July 14, 1997, indicated that the zinc levels in the 2A EDG had dropped to 11 ppm. The licensee replaced the oil in the 2D EDG on July 25, 1997.

The inspector discussed the review of the oil chemistry test results with the component engineer. The component engineer typically reviewed chemistry reports for oil samples after the report arrived at the site. The review process did not prompt questioning if expected sample reports were excessively delayed. The inspector concluded that weaknesses in the licensee's review of oil analysis reports permitted the introduction of the same high zinc oil into a second EDG.

This issue will remain open pending additional NRC inspection of the licensee's corrective actions to preclude recurrence of the problem. This item will be identified as Unresolved Item 50-260/97-08-02, Incorrect Oil Used in Two EDGs.

During investigation of the high zinc levels identified by chemistry oil samples, the licensee determined that an error had occurred during the review and change of TIIC numbers. TVA Corporate had evaluated lubricating oils for generic use in TVA's nuclear plants. Apparently, during the process, an incorrect generic oil substitute TIIC number was coded to replace the currently used EDG oil TIIC number. This incorrect oil was placed into two of the EDGs as discussed previously.

Another recent procurement example involved incorrect sized lightbulbs being used in Appendix R emergency lights. The licensee identified this issue in BFPER971175.

The inspector previously identified a concern that ethylene glycol could have been issued for use in the EDGs contrary to Site Standard Practice SSP-13.1, Chemistry Program. This issue was described in NRC IR 50-259,260,296/96-13.

The inspectors discussed their concerns regarding procurement deficiencies during a meeting with licensee management on August 5, 1997. Subsequently, the inspectors were briefed on the licensee's ongoing initiatives in the Materials/Procurement area. The licensee has identified numerous issues with the materials procurement processes at BFN and at the other nuclear sites. A team has been established which, in recent weeks, has finalized an action plan to address the Materials issues and potential actions for improvement. The inspectors specifically noted that this Materials Upgrade Project is expected to address the common causes of the concerns noted above. The licensee intends to address numerous other issues. For example, progress has been made regarding a careful review and identification of critical

parts for an important safety system. The proposed actions include extensive data base revisions and simplifications to complex processes. Additional NRC review of the Materials Upgrade Project is warranted. These issues are identified as Inspection Followup Item 50-260,296/97-08-05, Materials Upgrade Project.

c. Conclusions

Weaknesses in the licensee's lubrication oil analysis program permitted the incorrect type of lubricating oil to be added to a second EDG several months after it had been installed in a different EDG. An error in the Materials/Procurement processes resulted in workers procuring the incorrect oil for addition to the EDGs. Similar examples of procurement weaknesses have been identified previously. The licensee has initiated an extensive Materials Upgrade Project to address the issues.

E2.4 Plant Modifications

a. Inspection Scope (37550)

The inspector reviewed selected plant modifications in order to verify that (1) 10 CFR 50.59 Safety Evaluations were technically adequate and the screening criteria had been correctly applied; (2) plant modification packages identified all plant procedures that required revision because of the design changes; (3) post modification test scoping documents were technically adequate to demonstrate achievement of design objectives; and (4) work instructions adequately addressed the scope of the plant modification and was consistent with the hardware changes. Implementation of the design control process was also verified to have complied with the requirements of the licensee's ANSI N45.2.11-1974 design control program.

b. Observations and Findings

The following plant modifications were reviewed during this inspection:

- DCN No. T34764A, Replace Obsolete Melestrom Pressure Switches with SOR Pressure Switches, Revision 0.
- DCN No. T39722A, Modify RFW Heater Isolation Logic, Revision 0.
- DCN No. W35344A, Replace APRM/RBM with Power Range Neutron Monitors, Revision 0.

- DCN No. W36756A, Upgrade Scram Solenoid Valves, Revision 2.
- DCN No. S39677A, Revise Load Limitations, Revision 0.

The licensee's design control program permits the development and implementation of various alphabet designated plant modifications as defined in procedure SSP-9.3, Plant Modifications and Design Change Control, Revision 22, Section 5.0 Definitions. Review of the above two Ts, two Ws and one S plant modification revealed that in general the design change packages were developed and implemented in accordance with the design controls delineated in plant procedure SSP-9.3. The inspector considered the overall design control process to be complex and cumbersome because of the various administrative processes required for each type of plant modification. As a typical example plant procedure SSP-9.3 defined the S-DCN as a type of DCN that is used to support documentation changes only. An S-DCN shall not be used for setpoint changes, system realignment, nor labeling changes. This design process was used incorrectly for system alignment changes, as described in the following paragraphs.

Based on review of DCN No. S39677A the inspector determined that the scope of the design change involved revising load limitation notes on drawings 0-45E732-1, 0-45E732-3, 0-45E7349-1, and 1-45E749-2. The load limitation note was revised to permit simultaneous operation of transformers TS1E and TDE from the 4160 Volt Diesel Generator Auxiliary Board "B" based on a maximum load limit of 500 KVA. Design basis calculation ED-Q0057-950036, AC and DC Load Limitations for Units 2 and 3 Operating, was reviewed and verified to have established a load limit of 500 KVA for this system alignment. The licensee revised drawing numbers 0-45E732-1 and 0-45E732-3 which were FSAR Figures 8.5-12A and 8.5-13A respectively. An FSAR change request was also prepared as part of the DCN package in order to incorporate the design changes into the licensing basis document.

The inspector reviewed the Safety Assessment performed for plant modification DCN No. S39677A and determined that it failed to identify the need for a Safety Evaluation. Revision of the load limitation notes on the FSAR Figures changed the technical content of the Figures in the FSAR and should have been evaluated in accordance with the requirements of 10 CFR 50.59. This change permitted a new system alignment which had previously been prohibited because of the current licensing basis. The licensee failed to perform a 10 CFR 50.59 Safety Evaluation because the change was considered a documentation change only. This failure to

perform a 10 CFR 50.59 Safety Evaluation for simultaneous operation of transformers TS1E and TDE involving a new system alignment was identified as Violation 50-260/97-08-01,.Failure to perform a 10 CFR 50.59 Safety Evaluation for new system alignment.

The inspector reviewed the safety assessment/safety evaluation prepared for the other plant modifications in order to verify the technical adequacy and compliance with the requirements of 10 CFR 50.59. The safety assessments/safety evaluations correctly applied the screening criteria in assessing the impact of the changes to the plants licensing basis delineated in the UFSAR and the Technical Specification. Additionally, the safety assessments clearly described the changes implemented within the scope of the plant modifications and concluded that an unreviewed safety question did not exist because of the design changes. The inspector concurred with the conclusions documented.

The licensee's design controls required that DCN Impact Review Forms be completed by Systems Engineering, Operations and Maintenance for T and W-DCNs. Each organization was responsible for identifying the procedures/instructions, for which they have responsibility, that required revision prior to:

(1) Returning the modified equipment/system to operation

(2) Final closure of the DCN

Plant procedures or instructions that are required to maintain the systems in a functional/operable status were required to be revised prior to return to operation. Additionally, procedures other than those that are revised prior to return to operation need to be revised before closure of the DCN. Detail guidance for completing the Impact Review Forms was provided in Appendix E of SSP-9.3. The inspector reviewed completed Impact Review Forms for the above plant modifications and verified that the requirements had been satisfied.

One item was identified during this review in connection with DCN W36756A. This plant modification was prepared to replace existing ASCO scram solenoid pilot valves, scram discharge valves vent and drain pilot valves, and scram discharge valve isolation test valve with solenoid valves that had a longer qualified life. The Impact Review Form for this plant modification was verified as having been completed to initiate revision to procedure MCI-0-085-HCU001. The inspector determined, that mechanical corrective instruction MCI-0-085-SOL001 and

electrical corrective instruction ECI-0-085-SOL001 which implement essential maintenance requirements for Environmental Qualification Binder BFNOEQ-SOL-0010 were not listed as requiring revision on the Impact Review Form. Discussions with TVA management revealed that procedure MCI-0-085-HCU001 had been replaced by the two plant procedures identified above. Several changes in the ASCO valve model numbers were documented in the plant modification package and these changes occurred in response to industry wide concerns involving the elastomer material used with the valves. The most recent revision of the DCN identified the replacement SSPVs as ASCO model HV 266000-7J for which plant procedures had not yet been identified on the impact review forms. This omission appeared to be an anomaly in that the voiding of procedure MCI-0-085-HCU001 and its replacement by other procedures was not entered into TVA's document and records management system. Several changes in ASCO valve model numbers and elastomer types also exacerbated this situation. Problem Evaluation Report PER No. BFPER971046 was written to document this deficiency and initiate corrective action. The inspector considered this item to be of minor safety significance.

The inspector performed additional reviews of the plant modification packages including work completion statements. Drawings and design change authorizations required for completing the plant modification including post modification tests documents were identified in the work completion statements. Review of selected post modification test scoping documents revealed that test acceptance criteria were adequate to demonstrate achievement of design objective. No deficiencies were identified during this review.

c. Conclusion

The inspector concluded that the licensee was implementing the design control program in accordance with the requirements of ANSI N45.2.11-1974. One Violation was identified for failure to perform a 10 CFR 50.59 Safety Evaluation during implementation of an "S" DCN.

E2.5 Engineering Evaluations for Operability Determination

a. Inspection Scope (37550)

The inspector reviewed selected Technical Operability Evaluations (TOEs), in order to evaluate the technical adequacy of the formal engineering input used for aid in determining operability. The TOEs were also reviewed to verify compliance with the guidelines of Generic

Letter 91-18 for ensuring the functional capability of a system or component.

b. <u>Observations and Findings</u>

TOE No. 0-97-085-0974, Justification for Continued Operation with Scram Solenoid Valves Containing Incorrect Material

TOE No. 0-97-085-0974, Revision 0, was written to provide justification for continued operation with regard to potential safety related problem involving ASCO model HV 266000-007J solenoid pilot valves. The Automatic Switch Company (ASCO) in a letter to the NRC dated May 27, 1997, provided additional information concerning the potential safety related problem with ASCO model HV 266000-007J scram solenoid pilot valves (SSPVs). In this letter ASCO identified a total of six plants that had received the suspect SSPVs. Browns Ferry was listed as having received five. Corrective actions described in the letter included a Justification for Continued Operation (JCO) prepared by the General Electric Company and which were distributed to the affected plants. The JCO recommended that pre-tested pilot valves assemblies be installed on all suspect valves before they reach the predicted three to four year end-of-life. Additionally, the JCO recommended that augmented air leakage testing be considered for the plants until the changeout can be completed.

The inspector reviewed TVA's JCO in order to verify that GE's recommendations had been incorporated and compensatory actions were being taken for the degraded SSPVs. Based on this review the inspector determined that four Unit 2 SSPVs would be changed out at the next refueling outage (RFO) scheduled for the end of September 1997. Similarly, one Unit 3 SSPV would be changed out at the next RFO scheduled for September 1998. TVA concluded that the service life of the SSPVs based on their installation date was well within the GE recommended life of the elastomers. Compensatory actions to be performed for the Unit 3 SSPV will involve additional scram time testing on a frequency of 16 weeks for control rod 26-31 until replacement of the pilot head subassembly per WR C385168. The inspector identified no deficiencies during review of TOE No. 097-085-0974.

TOE No. 0-94-086-0169, D/G "D" Instrument Air Root Valve

TOE No. 0-94-086-0169 was written to evaluate the installation of a non-safety valve in a safety related system. System 086, diesel starting

air system right bank instrument root valve 0-RTV-086-0602D was installed by Work Order 91-39183-00 and was required to maintain system pressure for enabling the "D" diesel generator to start. The licensee determined that the apparent cause for installation of the non-safety valve to be an inadequate procedure in that procedure SSP-6.2. Maintenance Management System, did not provide clear guidance concerning replacement parts. The procedure paragraph 3.9.1 was revised on October 26, 1994, to preclude future occurrence of this issue. The installation was accepted as-is based on the valve design and post installation tests. The valve installed was a NUPRO B4J rated at 250 psi at 300 degree fahrenheit. System design temperature and pressure was given as 300 degree fahrenheit and 200 psi. The TOE was closed based on post maintenance tests results which verified no leakage through the seat and no visible leakage at the valve with the system in service.

The basis for closing the TOE did not consider seismic requirements. The inspector considers this to be of minor safety significance given the small mass of the instrument root valve and the redundancy designed into the diesel starting air system. Additionally, the inspector considered the licensee's corrective actions were adequate to prevent reoccurrence.

TOE No. 0-94-026-9006, Fire Pump Auto Start Circuit

This TOE was written to evaluate the installation of temporary jumpers on the fire pump auto start circuit while plant modification DCN No. W18627A was being implemented. The plant modification added redundant Class 1E fuses for cables FE100 and A1225 in order to resolve electrical separation concerns of non-safety related circuits degrading safety related circuits. Installation of the temporary jumpers provided electrical power from 120 VAC preferred bus on panel 9-24, breaker 512 to auto start terminal points WFX1 and WFY1. The auto start circuit was therefore enabled while fuses 0-FU2-026-512A and B were being installed. This temporary plant modification was implemented by work plan 0626-93 for which a 10 CFR 50.59 safety Evaluation had been performed. No deficiencies were identified during review of TOE No. 0-94-026-9006.

TOE No. 2-96-211-9003, Transformers TS1E and TDE Simultaneous Operation

This TOE was written to permit parallel operation of transformers TS1E and TDE from the 4160 V Shutdown Board "B" despite specified restrictions on approved design output drawings. The TOE failed to recognize that a plant modification should have been used to implement

this design change. Failure of the TOE to initiate a plant modification was recognized by TVA management and PER No. BFPER960512 was written to initiate DCN No. S39677A for revising the load limitations notes on drawings number 0-45E732-1, 0-45E732-3, 1-45E749-1, and 1-45E749-2. The DCN is further reviewed in Section E2.4.

The TOE documented a technical evaluation for the load limit specified on the referenced drawings and provided quantitative acceptance criteria of 77 Amps for a load limit of 555 KVA. The inspector reviewed design basis calculation ED-Q0057-950036, Revision 2 and verified that a load limit of 500 KVA had been established as the load restriction for simultaneous operation of transformers TS1E and TDE. Based on the load limit of 500 KVA the inspector calculated the load current to be 69.3 Amps which was different from the value given in the TOE.

The TOE also stated that procedure 0-OI-57B, 480/240 VAC Electrical System, Revision 53, should be revised to include instructions for simultaneous operation of transformers TS1E and TDE. The inspector reviewed the procedure and verified that the procedure had been revised to permit parallel operation of both transformers based on a load limit of 500 KVA. A 10 CFR 50.59 Safety Evaluation had also been performed to incorporate these load limit restrictions into revision 48 of the procedure. Section 3.14 delineated the precautions and limitations for parallel operation of the transformers. Based on review of the procedure, the inspector determined that the procedure did not provide quantitative acceptance criteria within the body of the procedure for parallel operation of transformers TS1E and TDE under load limiting conditions. Section 8.6 of the procedure delineates the instructions for transferring 480 V shutdown board "1A" from the normal to the alternate power supply. Section 8.10 provides similar instructions for transferring the 480 V diesel auxiliary board "A" from the normal to the alternate power supply. The procedure did not identify within either sections 8.6 or 8.10 a load limiting value of 500 KVA for system alignment implemented by performance of both of these sections. The licensee stated that the precaution and limitation statement in Section 3.14 which required calculation of the load current under this mode of plant operation was adequate for this plant evolution. The inspector considered the procedure adequate, however, omission of quantitative acceptance criteria within the body of the procedure could result in human errors. The Resident Inspector observed implementation of such an evolution as discussed in Section 01.2.

c. Conclusion

The inspector concluded that the TOEs were technically adequate with some minor exceptions.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Inspection Followup Item (IFI) 296/96-08-02, Emergency Core Cooling System (ECCS) Inverter Failures. This IFI addressed several failures of the Unit 3 ECCS inverters which have occurred since July 1996. The cause of the inverter failures and potential affects of ambient room temperatures were not fully understood. A total of five incidents have occurred on the Unit 3 inverters, inverter component replacements were required in four of the instances and in one case a fuse cleared. Inspection Reports 259,260,296/96-08, 96-12, and 96-13 contain description of NRC review of several of the incidents. The licensee has submitted Licensee Event Reports on the failures.

The licensee performed extensive investigation into the failures including:

- The failed Silicon Controlled Rectifiers (SCRs) were analyzed by a vendor and an independent testing company. The analysis noted that the epoxy encapsulant in the failed SCR did not completely fill the lower cavity and an air bubble may have been present. The SCR failed at a corner where it is most susceptible to voltage stress and the analysis concluded that the failures were related to an overvoltage condition.

- Extensive online monitoring of the inverters and investigation by the licensee ruled out potential causes such as electronic noise, radio transmissions, power supply transfers, or other plant evolutions. Reviews of Operating Experience Data indicated that inverter failures which had occurred at other facilities were not similar to these failures.

- A technical assessment was conducted by a TVA corporate electrical engineer and a representative of SCI. The review concluded that the most likely cause of four of the five failures was damaged or defective SCRs. The other failure (fuse clearing) apparently

involved a loose air-core inductor which shorted a capacitor bus. The review stated that the inverter vendor has concluded that the inverter components are optimized for stable operation for the range of voltage, loading, and ambient temperatures.

Corrective actions implemented included:

- 125 amp inverter fuses were replaced with 100 amp fuses on Unit 3 (and will be replaced on Unit 2).

- The failed SCRs were Solidstate Controls Incorporated (SCI) SCR type TD 42. The vendor has replaced TD 42 SCRs with TD 46 type. The TD 46 SCRs have larger I^2t ratings than the TD 42 SCRs.

- A modification (DCN T39853) was implemented on Unit 3 and is planned (DCN T39852) for Unit 2 which adds a 250 VDC to 24 VDC converter. This converter will provide an alternate supply to the Analog Trip Units if an inverter failure occurs. This significantly reduces the potential safety affects of an inverter failure.

IR 96-08 noted that a NRC inspector identified that some of the inverters did not have the minimum clearance to the wall stated in the vendor manual. The inspector noted that an SCI field service repair report, dated February 1997, stated that the inverter temperatures were well within limits. Problem Evaluation Report (PER) 961123 was initiated to address this issue. The inspector reviewed the completed PER. The licensee's investigation concluded that one of the causes of the problem was that the vendor instruction manual which contained the clearance requirements, was not supplied on the front end of the procurement process and thus the information was not incorporated into the installation design. The licensee concluded that the lack of clearance was not a factor in the recent failures and noted that the Unit 2 inverters are installed closer to the wall than the Unit 3 inverters and have not experienced the SCR failures. The licensee obtained concurrence from the vendor that the installed configuration is acceptable and incorporated documentation into the vendor manual. The inspector reviewed a memorandum which clearly stated that the vendor did not feel that the cabinet spacing was a problem. Site Engineering issued a memo to the Procurement Engineering Group reinforcing the obligation to obtain special design requirements on the front end of a contract and request that such information be addressed on vendor drawings so that it can be incorporated into the design package.

The inspector concluded that the licensee's overall investigative and corrective actions regarding the inverter failures were timely and effective. No failures of the replaced SCRs have occurred. The inverters are being monitored by the licensee as an a(1) system in accordance with the maintenance rule. The failures and corrective actions were well documented in the licensee's corrective action system. IFI 296/96-08-02 is closed.

E8.2 (Open) Inspection Followup Item 259,260,296/97-01-01. Resolution of FSAR Discrepancies. During a review of the Final Safety Analysis Report Section 4.7.7, the inspector questioned the following statement: "Testing of the RCIC pump discharge valve and air-operated check valve is accomplished by first shutting the upstream discharge valve." The licensee reviewed the statement and determined that a discrepancy existed between the FSAR statement and the way that the testing is currently conducted. The licensee initiated BFPER971070 on July 8, 1997. The IFI remains open pending additional NRC review of the licensee's UFSAR review program.

E8.3 (Closed) Licensee Event Report (LER) 260/95-009. Torus Water Level Exceeded Technical Specification (TS) Limit Due to a Past Engineering Error. This LER addressed the licensee's identification that a 2 inch offset in the narrow torus water level instrumentation had resulted in torus level slightly exceeding the -1 inch TS limit in the past. This issue was reviewed in detail by NRC inspectors as documented in IR 95-64. Non-Cited Violation 95-64-09, Violation of Torus Water Level TS, addressed the deficiency. The LER is closed.

E8.4 (Closed) Licensee Event Report (LER) 260/95-005. Failure of the High Pressure Coolant Injection Steam Supply Valve During Testing. The licensee determined that pitted seal-in contacts in the steam supply circuitry caused the problem. IR 95-31 describes NRC review immediately following the failure. The inspector reviewed closed PER 950690 and maintenance work records. The documentation indicated that the valve was stroked on September 8, 1995, (which verified the contacts were operating) and the contacts were inspected on December 1, 1995. Work Order 95-14730-00 stated that the contacts were found in good condition. The inspector also verified that procedure EPI-0-000-MCC001 is scheduled to be performed on the breaker during the upcoming refueling outage. No other problems with these contacts have occurred since the 1995 failure. The LER is closed.

E8.5 Ellis and Watts Procurement Activities

a. Inspection Scope (37550)

In April of 1996 TVA's Vendor Audit Services received information from NUPIC concerning continuing weaknesses in Ellis and Watts commercial grade dedication processes and this vendor was removed from the Accepted Supplier List (ASL). Vendor surveillance report number 96S-18, dated June 17, 1996, documented TVA's evaluation of commercial grade dedication packages for several Browns Ferry purchase orders. The vendor surveillance was performed at Ellis and Watts, Batavia, Ohio on May 9-10, 1996. The inspector conducted interviews with TVA's personnel from the Procurement Engineering Group (PEG) and reviewed objective evidence which provided reasonable assurance that material accepted from Ellis and Watts had met specified technical and quality requirements. The following documents the results of this review:

b. Observations and Findings

Purchase Order (PO) 96N2D-156126 was issued for two Spartan solenoid valves which had not yet been shipped at the time of the evaluation. This contract was canceled and the material was never received from the vendor.

PO 96N2R-167653 was issued for ten Spartan solenoid valves. TVA approved Ellis and Watts revised commercial grade dedication plan CDPN-0723 on May 10, 1996. Critical characteristics had been verified by a combination of inspection and commercial grade survey. Additionally, a sample of these valves were examined and no deficiencies were identified. The material was received and accepted from the vendor.

PO 95N2R-171612 was issued for two solenoid valves; this material was processed and received prior to the vendor being removed from the ASL. Commercial dedication plan CDPN-0729 was approved by TVA and critical characteristics were verified by a combination of inspection and commercial grade survey. The package was determined to be acceptable.

PO 95N2R-149040 was issued for two Metrex chiller valves. Commercial dedication plan CDPN-0702 was reviewed and approved by TVA with the following exceptions:

- Verification of material for pressure boundary items was not validated by the vendor.

- Hydro test pressure values documented in the CDPN and the actual test results were different. The CDPN showed test pressure of 280 psig and the test report specified 225 psig.

Additionally, PO 96N2R-16556 issued for three Metrex chiller valves was determined to be satisfactory based on review of dedication plan CDPN-0719 with an exception similar to the first one identified above. The exceptions were resolved via correspondence with the vendor and material tests performed by TVA's Central Laboratory Services. The chemical composition of the valve material was identified in Central Laboratory Services Technical Report No. 96-1098, dated July 8, 1996.

PO 96N2R-166372 was issued for one crank case heater and its commercial grade dedication plan CDPN-0720 was reviewed and approved by TVA. An examination of the heater revealed, however, that it differed from the sketch provided by the vendor with regard to the length of the leads required for power connection. The two heaters also differed in appearance. Based on the results of TVA's investigation of this issue one heater was determined to be acceptable for shipment and the other was not released for shipment pending the vendor making an equivalency determination for the other.

c. Conclusions

The inspector concluded that the actions taken by TVA for release of material received from Ellis and Watts was adequate to ensure that technical and quality requirements involving critical characteristics of procured items were satisfactory.

E8.6 (Closed) VIO 50-259, 260, 296/EA 95-220: This violation identified that on February 2 and 4, 1993, the licensee failed to ensure that the provisions of 10 CFR 50.7 were implemented in that Stone and Webster Engineering Corporation, a contractor to the Tennessee Valley Authority at the Browns Ferry Nuclear Plant, discriminated against a worker engaged in a protected activities.

Specific corrective action for this violation was reviewed and documented in NRC Inspection Report 50-260, 296/96-13. This violation is closed for record purposes; however, the staff will continue to monitor plant specific indicators related to discriminatory employment practices. These indicators include, in part, allegations of discrimination reported to the NRC and proceedings initiated as a result of complaints made to the Department of Labor alleging discrimination

practices. These indicators include, in part, allegations of discrimination reported to the NRC and proceedings initiated as a result of complaints made to the Department of Labor alleging discrimination for engaging in protected activity.

IV. Plant Support

R4 Staff Knowledge and Performance in Radiological Controls and Chemistry

R4.1 Sampling of Raw Cooling Water

a. Inspection Scope (71750)

The inspector observed sampling of the Raw Cooling Water (RCW) system. In accordance with Inspection Procedure 71750, compliance with procedural and Offsite Dose Calculation Manual (ODCM) requirements was examined.

b. Observations and Findings

On July 17, 1997, one of the inspectors observed sampling of the Unit 1 RCW system. The sampling and analysis was being conducted because the Unit 1 RCW effluent radiation monitor (RM-90-132D) was inoperable. Table 1.1-1 of the ODCM (Action D) requires sampling at least once every eight hours during RCW releases when the monitor is inoperable. The monitor had been inoperable since July 4, 1997. The inspector observed that the licensee had good administrative methods to ensure that the sampling was performed within the required intervals. Once per six hour sampling requirements were actively tracked by the Chemistry Shift Supervisors and turned over between the Radiological Laboratory Assistants (RLAs). The data package for completion of the procedure contained signatures for verification that the time requirements were met for each sample.

The sampling and analysis is controlled by Surveillance Instruction 0-SI-4.2.D-3B, RCW Effluent Radiation Monitor (Off-Line) Inoperable, and Chemistry Instruction (CI)-403, Reactor Building Sampling Procedure. The RLA notified the Unit 1 Operator and reviewed the surveillance requirements prior to obtaining the sample. However, the RLA did not perform several steps in accordance with the procedure.

Step 7.7 of 0-SI-4.2.D-3B states that the sample volume is to be collected for gamma scan per Attachment 15 of CI-403. Step 1.2 of CI-

403 required that valve 1-24-880 be verified open. This valve is a small manual isolation valve between the RCW outlet line and the sample pump. The RLA failed to verify that the valve was open.

Step 1.3 of CI-403 required the worker to check the operating status of the sample pump. Sampling is performed differently depending on sample pump status. The step contained specific directions that the sample pump is operating if the "MOTOR ON" light on Panel 25-336 is illuminated. The sample pump is not operating if the "MOTOR OFF" light is illuminated or if all Panel 25-366 lights are extinguished. All the lights were extinguished. (The error in panel numbers had been previously identified and was being addressed). In response to the inspector's questions, the worker discussed that he had verified that the pump was operating by direct observation of the pump and sample flow indication on the panel instead of the procedural requirements. The inspector observed that the sample pump appeared to be running and there was sample flow indicated. Subsequently, it was determined that the "MOTOR ON" light bulb had burned out.

The remaining steps were performed as required. The RLA also contacted Operations and requested independent verification that the sample valve had been shut. Required information was entered on the data sheets for 0-SI-4.2.D-3B and a gamma scan was performed. The printout of the gamma scan was forwarded to the Chemistry Shift Supervisor (CSS) for review. Steps 7.10-7.12 of the SI require the CSS to review the data and verify acceptance criteria were met. The printout listed minimum detectable activity (MDA) in microcuries per milliliter for different isotopes in the sample and stated that no activity had been identified in the sample. The inspector asked the CSS how he verified the acceptance criteria that the Lower Limit of Detection (LLD) of the analysis was less than the Effluent Concentration Limit (ECL) (total) as described in step 7.9.3 of the SI. The CSS responded that he was not sure how to do that from the data on the printout. Subsequently, Chemistry department supervision informed the inspector that the counting equipment in the lab was set up to meet the requirements for Lower Limit of Detection. This was accomplished by setting a conservative minimum count time period into the routine used by the RLAs to count the samples.

The inspector noted two minor administrative errors in the procedure. Attachment 2 of 0-SI-4.2.D-3B (page 9 of 9) contained an incorrect title line and referenced the Residual Heat Removal Service Water radiation monitor. The inspector was subsequently informed that this error had been detected the previous week and was being corrected. Step 1.3 of

the SI contained an incorrect panel reference number. The inspector was informed that Chemistry personnel had recently identified that error as well and would correct it.

Browns Ferry Technical Specification (TS) 6.8.1.1.i requires that written procedures shall be established, implemented, and maintained covering the activities referenced in the ODCM. Table 1.1-1 of the ODCM states that releases of RCW may continue, with the number of radiation monitoring instrumentation channels less than the required minimum, provided that a temporary monitor is installed or at least once per eight hours grab samples are collected and analyzed for radioactivity. The worker did not correctly implement written procedure CI-403 which is utilized to accomplish the ODCM requirements. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the Enforcement Policy. The violation had no actual impact on the validity of the raw cooling water sample. This is addressed as Non-Cited Violation 259/97-08-04, Failure to Follow Chemistry Sampling Procedure.

c. Conclusions

The licensee had strong administrative controls in place to minimize the possibility of missing a ODCM required compensatory RCW sample. The CSS indicated to the inspector that he was not aware of how the LLD acceptance criteria (stated in ODCM and the procedure) was met, although it was his responsibility to verify that the criteria was met. The worker did not fully comply with the sampling procedure. The safety significance of the specific deficiencies was small since the overall intent of the steps was met. However, considering that Chemistry department management has been emphasizing procedural compliance in recent months, the inspector concluded that the deficiency should be addressed by the licensee. The inspector noted indications that management has also initiated efforts to improve Chemistry procedures.

R8 Miscellaneous Radiological Protection and Chemistry Issues

R8.1 Review of 10CFR19 Required Postings

a. Scope (71707.71750)

In accordance with the guidance in Inspection Procedure 71707, the inspector performed a review of the licensee's 10 CFR 19 required postings at selected bulletin boards around the site.

b. Observations and Findings

On June 25, 1997, the inspector noted that an outdated NRC Form 3 was posted on a bulletin board at the East Gatehouse protected area entry point. The inspector brought this to the attention of the Site Licensing Supervisor and a problem evaluation report (PER) BFPER971039 was initiated. In addition, a current copy of Form 3 was temporarily placed over the outdated version which was in a locked case and could not immediately be removed. Subsequently, the licensee informed the inspector that the board was not the licensee's required board, but was maintained by a contractor. The NRC Form 3 was removed from the board.

The inspector also noted that an old version of 10 CFR Part 19 was posted. The inspector discussed with the licensee how the required postings were maintained. The licensee indicated that they perform a periodic review of the posted documents at seven locations around the plant. The most recent review was performed on June 5, 1997. The licensee addressed the outdated version of 10 CFR Part 19 by adding an item to the periodic review checklist to replace 10 CFR 19, 21 from the NRC Rules and Regulations.

On July 11, 1997, the inspector sampled four of the seven places that the licensee displays 10 CFR 19 required postings. The East and West Gatehouse boards included the NRC Form 3, Part 19, Part 21, and a licensee Notice to Employees which discusses required postings and where they can be viewed. The remaining two boards sampled included the NRC Form 3 and the licensee Notice to Employees.

The inspectors questioned the clarity of some of the items in the Notice to Employees. On July 17, 1997, the inspector discussed changes made by the licensee to the Notice to Employees. The licensee clarified the contacts for assistance in reviewing required documents. In addition, the licensee clarified the posting to more accurately reflect the NRC position on identity protection of individuals that present their concerns to the NRC. The inspectors considered that the licensee's actions were acceptable.

R8.2 (Closed) Inspection Followup Item (IFI) 259, 296/95-55-01, Review of Licensee FSAR Commitments for CAMs associated with Units 1 and 3. Review of this item was documented in Inspection Report 96-06 but due to an administrative oversight the item was not closed out. The review was sufficient to close out the item, the IFI is closed.

P1 Conduct of Emergency Preparedness Activities

P1.1 EP Training Exercise

a. Inspection Scope (71750)

The inspector observed portions of the emergency preparedness training drill which was administered on July 30, 1997.

b. Observations and Findings

The inspector observed the drill from the Technical Support Center (TSC). The drill appeared to be a good training opportunity for participants. The participants in the TSC provided recommendations for improvements during the post drill critique.

P8 Miscellaneous Security and Safeguards Issues

P8.1 (Closed) Violation 50-259,260,296/96-10-01, Failure to Adequately Control Unattended Vehicles Within the Protected Area. The inspectors reviewed the licensee's corrective actions which included a notice to vehicle drivers entering the protected area, a Site Security memorandum which directed patrols to increase checks and searches of designated vehicles within the protected area, and training of Facilities and Instrument and Controls personnel. In addition, the licensee addressed control of vehicles within the protected area in the Plan of the Day Report dated September 23, 1996. The inspectors sampled vehicles to ensure that the vehicles were controlled. This item is closed.

P8 Miscellaneous EP Issues

P8.2 (Closed) Unresolved Item (URI) 50-260,296/96-05-04: Dose Assessment capability. This item was opened to evaluate whether, in the event of an emergency at Browns Ferry, methods were in place for on-shift personnel to perform basic offsite dose calculations using real time meteorological data.

Subsequent detailed in-office review of the licensee's Emergency Plan determined that the licensee had not committed to have on-shift dose assessment capability. Subsequently, the licensee revised Emergency Plan to provide for on-shift dose assessment capability and revised their Emergency Plan Implementing Procedure EPIP 14, Radiological Control Procedures, Revision 11, to provide that capability.

The licensee's submitted change to Emergency Plan Implementing Procedures (EPIP) 14, Radiological Control Procedures, Revision 12, deleted Section 3.9 from EPIP 14, Revision 11. Section 3.9 had instructed on-shift personnel to run Forecast Radiological Emergency Dose (FRED) to make emergency classifications in the event of a radiological release. FRED was the licensee's dose assessment computer located in the Technical Support Center (TSC).

Other changes in EPIP 14, Revision 12, enhanced the manual method for offsite dose calculation by adding two tables with multiplication factors, one for a stack release, and one for a building or ground release. The multiplication factors were selected, based upon wind speed and stability class for distance of 1 mile, 5 miles, and 10 miles from the plant. To determine the dose rate, the radiological release rate was multiplied by these multiplication factors. The inspectors worked through the procedure without any difficulty. EPIP 14, Revision 12 was of sufficient detail to permit on-shift personnel to perform a basic dose calculation at given distances for the plant using real time meteorological data.

V. Management Meetings

X1 Exit Meeting Summary

The resident inspectors presented inspection findings and results to licensee management on August 5, 1997. Other meetings to discuss report issues were conducted during the report period. A formal meeting with plant management was also conducted on July 11, 1997. During the July 11, 1997, meeting, the licensee indicated that additional discussion was appropriate regarding two findings in the engineering areas. A subsequent telephone call with NRC Region II (RII) management and a reactor engineer from the RII staff, reviewed the licensee's position on the two findings.

A subsequent exit meeting was conducted on August 20, 1997, after additional information was available regarding the High Pressure Coolant Injection system problem, the Standby Gas Treatment System testing items, and the engineering review issues. 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
R. Coleman, Acting Radiological Control Manager
J. Corey, Radiological Controls and Chemistry Manager
T. Cornelius, Emergency Preparedness and Planning
C. Crane, Site Vice President, Browns Ferry
R. Greenman, Training Manager
J. Johnson, Site Quality Assurance Manager
R. Jones, Assistant Plant Manager
S. Kane, Acting Site Licensing Supervisor
G. Little, Acting Operations Manager
K. Singer, Plant Manager
J. Schlessel, Acting Maintenance Manager
H. Williams, Site Engineering Manager

INSPECTION PROCEDURES USED

IP 37550: Engineering
IP 37551: Onsite Engineering
IP 40500: Licensee Self-Assessments
IP 62707: Maintenance Observations
IP 61726: Surveillance Observations
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 73756: Inservice Testing of Pumps and Valves
IP 81502: Fitness For Duty Program
IP 92901: Followup-Plant Operations
IP 92902: Followup-Maintenance
IP 92903: Followup-Engineering
IP 93702: Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, DISCUSSED, AND CLOSED

OPENED

Type	Item Number	Status	Description and Reference
VIO	50-260/97-08-01	Open	Failure to perform a 10 CFR 50.59 Safety Evaluation for New System Alignment (Section E2.4)
URI	260/97-08-02	Open	Incorrect Oil Used in Two EDGs (Section E2.3)
NCV	260/97-08-03	Closed	Failure to Identify Water Intrusion into HPCI System Junction Box (Section E2.1)
NCV	259/97-08-04	Closed	Failure to Follow Chemistry Sampling Procedure (Section R4.1)
IFI	260,296/97-08-05	Open	Materials Upgrade Project (Section M8.4 and E2.3)

DISCUSSED

Type	Item Number	Status	Description and Reference
IFI	259,260,296/97-01-01	Open	Resolution of FSAR Discrepancies (Section E8.2)

CLOSED

Type	Item Number	Status	Description and Reference
LER	296/95-008	Closed	Core Thermal Power Exceeded Operating License's Maximum Power Level Due to a Drifting Temperature Transmitter (Section 08.1)
VIO	296/95-64-01	Closed	Fire Protection Program Equipment Inoperable Without Compensatory Actions (Section 08.2)
VIO	260/96-03-01	Closed	Failure to Follow Procedures During Core Spray Valve Maintenance (Section M8.1)

VIO	260/96-04-01	Closed	Licensee Identified Appendix R Deficiencies (Section M8.2)
VIO	259,260,296/EA 95-220	Closed	Violation of 10 CFR 50.7 (Section E8.6)
LER	260/96-001-00	Closed	10 CFR Part 50 Appendix R Noncompliance Results in the Plant Being Outside Its Design Basis and Being in a Condition Not Covered by Plant Operating Instructions (Section M8.3)
URI	259,260,296/96-13-02	Closed	Toolpouch Issues (Section M8.4)
IFI	296/96-08-02	Closed	Emergency Core Cooling System (ECCS) Inverter Failures (Section E8.1)
LER	260/95-009	Closed	Torus Water Level Exceeded Technical Specifications (TS) Limit Due to a Past Engineering Error (Section E8.3)
LER	260/95-005	Closed	Failure of the High Pressure Coolant Injection System Supply Valve During Testing (Section E8.4)
IFI	259,296/95-55-01	Closed	Review of Licensee FSAR Commitments for CAMs Associated with Units 1 & 3 (Section R8.2)
VIO	259,260,296/96-10-01	Closed	Failure to Adequately Control Unattended Vehicles Within the Protected Area (Section P8.1)
URI	50-260,296/96-05-04	Closed	On-shift Dose Assessment capability, pending additional NRC review (Section P8.2).