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:	August 3 - September 13, 1997
Inspectors:	L. Wert, Senior Resident Inspector (SRI) J. Starefos, Resident Inspector D. Thompson, Special Inspections Inspector (Sections S3, S6, S7, S8) P. Taylor, Project Engineer C. Patterson, SRI - Brunswick (Sections O8.1, M8.1-8.3, E8.2-8.3)
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 50-259/97-09, 50-260/97-09, 50-296/97-09

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 security area by a Region II inspector.

Operations

Initial review of the failure of containment isolation valve 3-FCV-64-34 to close during a test raised questions regarding the operability status of the valve when it failed to close after the problem was believed to have been resolved. Additional review of the sequence of events and the specific failure mechanism is necessary to determine if a violation of regulatory requirements occurred. (Unresolved Item 50-296/97-09-06, Actions for Inoperable Containment Isolation Valve, Section O1.1).

During Plant Operations Review Committee (PORC) meetings, the committee conducted good reviews of the presented material. PORC members asked probing questions regarding the overall safety of the activities and appropriately focused on whether the change represented an unreviewed safety question or was prohibited by Technical Specifications. (Section O7.1)

Maintenance

The inspectors identified that the licensee was not properly implementing procedural controls over scaffolding in the Unit 2 reactor building. In some cases, scaffolds near safety related equipment were not constructed in accordance with limitations in the procedure or in the required engineering evaluation. The scaffolding assembly checklist was not being properly completed. Some procedural requirements, which would be difficult to complete, were not being implemented. No safety systems were rendered inoperable by the noted deficiencies. The inspectors concluded that the number and nature of the deficiencies indicate that supervisory personnel are not enforcing standards and failed to ensure that procedural requirements are satisfactorily met. (Violation 260/97-09-02, Scaffolding Controls Not Properly Implemented, Section M1.1).

The inspectors identified that the licensee was conducting functional testing of snubbers on safety related systems with the unit at power. Technical specifications state that snubber functional testing is to be performed during refueling outages. Procedural controls for the testing did not adequately enforce the TS requirements. (Violation 260/97-09-01, Functional Testing of Snubbers While Not in Refueling Outage Conditions, Section M1.2).

Observation of several selected maintenance activities indicated that the work was well planned and executed. Specifically, As Low As Reasonably Achievable (ALARA) planning of contingencies was good with regard to the high radiation evolution observed. The prejob brief in preparation for C3 emergency equipment cooling water pump work was strong. (Sections M1.3-1.5)

Engineering

Review of residual heat removal system service water pump inservice testing data and methodology indicated that the repeatability and effectiveness of the testing could be improved. Inspection Followup Item 50-260,296/97-09-07, RHRSW/EECW Pump Flow Testing Issues. (Section E1.1)

The licensee's actions regarding pressurization of portions of the Unit 2 shutdown cooling suction piping were acceptable. The licensee pursued the problem in a reasonable manner and the present conditions do not represent an immediate safety concern. Licensee management has indicated that the intent is to effectively address the issue such that it will not exist once the unit is returned to power after the refueling outage. (Section E2.1)

Plant Support

A random review of plans, records, reports, and interviews with appropriate individuals verified that security plan and procedure changes did not decrease the effectiveness of the Physical Security Plan. (Section S3.1)

Licensee management provided appropriate and excellent support for the Physical Security Program. Examples of the excellent management support were the support in preparation for the Operational Safeguards Response Evaluation and the excellent maintenance and engineering support for the security equipment. (Section S6.1)

The licensee evaluated hardware and mechanical problems associated with security equipment and the problems were effectively controlled and managed. (Section S6.2)

Licensee-conducted audits were thorough, complete, and effective in terms of uncovering weaknesses in the security system, procedures, and practices. The last audit report concluded that the security program was effective and recommended appropriate action to improve the effectiveness of the security program. The licensee had acted appropriately in response to recommendations made in the audit report. (Section S7.1)

High pressure fire protection system flushing was completed according to the work instructions. The procedure was actively utilized and the workers were knowledgeable of the evolution. Radio communications were appropriately formal and the workers were careful when draining the system to minimize overflow of the floor drains. (Section F2)

Report Details

Summary of Plant Status

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

Unit 2 reduced power to 83% on August 18, 1997, due to a water leak in the 2A high pressure heater room. On August 23, 1997, the U2C9 coastdown began with all rods out, recirculation flow at 100%, and final feedwater reduction implemented.

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

During some of the inspections discussed in this report, the inspectors reviewed applicable portions of the Updated Final Safety Analysis Report (UFSAR) that related to the areas inspected. No deficiencies were identified during the reviews.

I. Operations

01 Conduct of Operations

01.1 Suppression Chamber Standby Gas Inboard Isolation Valve

a. Scope (71707)

The inspectors reviewed licensee actions taken after the suppression chamber standby gas inboard isolation valve (3-FCV-64-34) failed to close during a surveillance test on July 26, 1997.

b. Observations and Findings

On July 26, 1997, during surveillance testing, the licensee identified that valve 3-FCV-64-34 failed to close when demanded. This valve is a Group 6 containment isolation valve located in piping connected to the suppression chamber. The valve closed during a subsequent attempt and was cycled several additional times. The licensee began cycling the valve once every four hours to ensure continued operability. The licensee submitted a work request to repair the valve and subsequently issued a Technical Operability Evaluation (TOE) on July 29, 1997. The TOE analysis determined that continued operation, every four hours, of the valve was no longer necessary and that CR120 relay 86-64-34 would be replaced. In the past, the CR120 relays had been observed to stick in the energized position if they were energized for a long period of time. The licensee concluded that the primary containment isolation system (PCIS) closure function of the 3-FCV-64-34 valve would not be inhibited by the problem with the 86-64-34 relay. TOE 3-97-064-1159, Revision 0 concluded that valve 3-FCV-64-34 would perform its safety function and that the system remained operable.

On August 14, 1997, the 3-FCV-64-34 valve failed to close again when tested. The 86-64-34 relay was replaced on August 19, 1997, and post maintenance testing was completed satisfactorily. On August 24, 1997, the 3-FCV-64-34 valve failed to close during performance of surveillance testing. The valve handswitch was cycled two more times before the valve closed. The licensee determined that the TOE still applied, there was not a PCIS operability concern, and continued troubleshooting. On August 28, 1997, with a contingency work order planned for immediate replacement of the solenoid valve associated with 3-FCV-64-34, another attempt was made to close the 3-FCV-64-34 valve. The valve took several seconds to close following operator action to turn the handswitch to the close position. The licensee declared the valve inoperable due to slow closure time and subsequently replaced the ASCO solenoid valve which is used to control the 3-FCV-64-34 valve. (Section M1.5 of this report describes NRC inspection of the replacement activity.) A failure of the solenoid valve would affect the ability of the valve to close which is the PCIS required position.

After reviewing the sequence of events associated with the valve failure, the inspectors questioned licensee management regarding the valve operability status on August 24 when it failed to close after the problem was believed to have been resolved. Licensee management reviewed the event and concluded that TS requirements for an inoperable containment isolation valve had not been met. The licensee plans to submit a 10CFR50.73 report.

This issue is identified as Unresolved Item (URI) 50-296/97-09-06, Actions for Inoperable Containment Isolation Valve, pending additional review of details regarding the timeliness of the licensee's actions.

The licensee is reviewing the cause of the solenoid valve failure. Preliminary indications are that sticking at the core-plugnut interface (CPI) may have contributed to the failure. The licensee disassembled the solenoid valve and identified that a varnish-like substance existed at the CPI. The licensee plans to remove two additional solenoid valves used in similar applications in the plant, in addition to the failed solenoid valve, and have an evaluation performed. A similar problem was previously identified in Inspection Followup Item (IFI) 260,296/95-64-10, Secondary Containment Ventilation Damper Failures, and updated in NRC Inspection Report 259,260,296/96-008. IFI 260,296/95-64-10 remains open.

c. Conclusions

The inspectors concluded that since the licensee had initially identified the CR120 relay as the apparent cause of the symptoms and had replaced the relay, the 3-FCV-64-34 valve should have been declared inoperable when it subsequently failed. Additional review of the sequence of events is necessary to determine if a regulatory violation occurred.

01.2 Observation of Assistant Unit Operator Rounds

a. Scope (71707)

The inspectors observed the Unit 3 Rounds Assistant Unit Operator (AUO) while he performed portions of Turbine Building Rounds.

b. Observations and Findings

On August 30, 1997, the inspector observed the Unit 3 Rounds Assistant Unit Operator (AUO) while he performed portions of Turbine Building Rounds. The inspector noted that, in light of recently identified scaffold problems, the AUO was sensitive to scaffolding in the plant. The inspector also noted that the AUO initiated work requests for identified problems and maintained housekeeping.

07 Quality Assurance in Operations

07.1 Plant Operations Review Committee Meeting

a. Inspection Scope (71707)

The inspectors attended four Plant Operations Review Committee (PORC) meetings. In addition to assessing the quality of the reviews, the inspectors verified that selected requirements of Technical Specification 6.5.1 and Site Standard Practice SSP-12.10, Plant Operations Review Committee, were met.

b. Observations and Findings

Each of the meetings was chaired by the Acting Operations Manager. It was clear that he was in charge of the meetings. An appropriate level of formality was maintained during the meetings. The committee actively questioned individuals presenting material for review. The PORC composition met the requirements of TS 6.5.1.2.a. Specific items noted:

- During review of a safety evaluation for use of a temporary power supply for the neutron monitoring system during a battery replacement, the PORC asked detailed questions regarding the qualification of the temporary supply. The evaluation was not approved since the presenter could not answer several of the PORC's questions.

- The PORC did not approve a request to delete Updated Final Safety Analysis Report (UFSAR) section 13.10.2.8 which described feedwater system operational testing. The PORC indicated that the UFSAR description should be revised to reflect the proper testing criteria if the current description is inaccurate, but the section should not be deleted.

- The PORC did not approve a proposed design change associated with the main steam relief valve automatic actuation logic since there were too many items remaining as "open" in the proposed modification.

- The PORC chairman ensured that only authorized personnel were present when an issue involving safeguards information was discussed.

- The PORC reviewed "A" level Problem Evaluation Report 960204, UFSAR Issues. The PORC requested that the presenters return with stronger explanations of the underlying issues and corrective actions.

c. Conclusions

The inspectors concluded that the PORC conducted adequate reviews of the presented material. PORC members asked probing questions regarding the overall safety of the activity and focused on whether the change represented an unreviewed safety question or was prohibited by Technical Specifications.

08 Miscellaneous Operations Issues (92901)

08.1 (Closed) Licensee Event Report (LER) 296/96-002-00, Unit 3 Scram Following Loss Of Reactor Feedpump 3C. This event was discussed in Inspection Report 96-04. The cause of the scram was due to low reactor water level caused by loss of the 3C reactor feedpump resulting from improperly aligned oil valves. A personnel error occurred while aligning the feedpump oil tank to the purification system. The oil tank was drained causing the feedpump to trip. The plant design is such that a loss of a single reactor feedpump can be compensated for by increased output of the other two reactor feedpumps in combination with an automatic run back of the reactor recirculation system pumps. In this case, reverse flow occurred through the 3C reactor feedpump line due to a damaged discharge check valve. The damage to the check valve was also discussed in Inspection Report 96-04 with long term resolution of this problem tracked by Inspection Followup Item 296/96-04-04 that remains open. Personnel corrective action was taken with the operator responsible for the valve misalignment. The inspector reviewed the Inspection Report and LER. All issues had been previously discussed or tracked. This LER is closed.

08.2 (Closed) Violation 296/96-12-01, Failure to Ensure Proper Position of EDG Aux Board Room Exhaust Fans. This violation addressed instances in which NRC inspectors found the switches for the Unit 3 EDG auxiliary board room exhaust fans not positioned in accordance with the system Operating Instruction. The inspector verified that procedures 0-OI-30F and 0-GOI-300-1 have been revised to clearly indicate when the fans can be turned off. OI-30F states that the fans shall be operating when ambient outside temperature is 40 degrees F or above. Verification of the Unit 3 exhaust fans has also been added to procedure 0-GOI-300-1.

The inspectors have noted on tours that the fan control switches have been maintained in the correct position and that the fans were running. Currently, caution tags are installed on the Unit 3 fan switches to ensure that the fans remain energized. The violation is closed.

O8.3 (CLOSED) Violation 296/96-13-03, Uncontrolled Locked High Radiation Area (LHRA). This violation occurred on December 27, 1996, while the Unit 3 3A1/3A2 Heater Room, which is normally posted as a LHRA, was de-posted to support maintenance activities when extraction steam was isolated. The area became a High Radiation Area again when operations personnel inadvertently introduced a radiation source to the room by manipulating an extraction steam valve.

The inspector verified that the latest revision of Operating Instruction 3-OI-6, Feedwater Heating and Misc Drains System, included a statement to notify Radcon personnel prior to making changes in Feedwater Heating System alignments which could cause a rise in area radiation levels. The procedure further required confirmation, to be obtained prior to performing the alignment, that Radcon has implemented appropriate radiological controls/barriers for the expected Feedwater Heating System alignment. In addition, the inspector noted that the licensee identified 22 Operating Instructions which were also revised to include the precaution. The inspector sampled seven of the identified procedures and verified that the procedures included the precaution in the latest revision. The inspector also verified that Site Standard Practice SSP-12.1, Conduct of Operations was revised to ensure that plant radiological personnel are informed prior to evolutions or activities which have the potential to significantly change radiological conditions.

The inspector noted that during the recent Unit 2 feedwater temperature reduction, the licensee used caution orders to ensure that Radcon personnel were contacted prior to operating heater extraction steam isolation valves so that Radcon could evaluate radiological conditions. The inspector concluded that the licensee's actions were adequate. This violation is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Scaffolds and Temporary Platforms

a. Inspection Scope (62707)

On August 26, 1997, the inspector examined 20 scaffolds/platforms located in the Unit 2 reactor building. The scaffolds/platforms were reviewed with regard to the requirements in Technical Instruction 0-TI-264, Scaffolds and Temporary Platforms. The inspector focused on verification of proper clearance between the scaffolds and safety related equipment.

b. Observations and Findings

During the course of the review, the inspector identified several specific examples in which the procedural guidance was not being correctly followed. Additionally, the inspector noted at least one issue in which the procedural expectations appeared to be not realistic and were not being applied. Several problems with the procedure were also identified.

- General precaution 4.4 and step 7.11.4 of 0-TI-264 require that areas around scaffolds which can be used for handholds or footholds shall be posted with caution signs and/or tape to avoid use as handholds or footholds. The erecting foreman is supposed to review and verify this when he signs the permit. The inspector did not observe any such marking of potential handholds or footholds. In the case of scaffold 2575-02, a conduit going into junction box 73-0111 was bent slightly and appeared to have been stepped on. These procedural requirements apparently are related to commitments made to the NRC as part of Licensee Event Report 260/89-006. In that event, personnel climbed on a reactor protection system breaker cabinet to access a scaffold.

- Appendix M (Scaffold/Temporary Platform Erection Checklist) of 0-TI-264 references steps 2.6.7 and 2.7.6 of Appendix L (Seismic Qualifications of Scaffolding and Platforms in Class I Structures). There is currently no step 2.6.7 in Appendix L and step 2.7.6 does not address clearance issues. It appeared that the correct reference would be step 2.7.7.

- Numerous examples were noted in which the Appendix M checklist indicated that the clearance requirements of Appendix L were met but a Site Engineering evaluation (Appendix N) was completed to address deviations from the clearance criteria. The inspector noted several indications that the Appendix M checklists were not being completed in a diligent manner.

- Section 2.7.7 of the TI states that if the clearance requirements can not physically be achieved, Site Engineering evaluation and approval shall be obtained and documented on Appendix N <u>prior</u> to erecting the portion of the scaffold in which the clearance cannot be achieved. The inspector noted that actual practice is to complete the site engineering evaluation in parallel with or after the scaffold is built.

- While no scaffolds were found with expired tags, the inspector noted that the expiration dates were often set far past expected end of work activities. For example, most of the refueling outage scaffolds had expiration dates of December 31, 1997. Apparently, the scaffolds are being tagged this way due to a perception that there may be delays in removing all the scaffolds following the outage.

- The inspector noted that in several cases, scaffolds were built with unnecessarily small clearances to safety related equipment. In most cases, the deviations were addressed in site engineering evaluations as required. However, larger clearances could have been physically achieved and there did not appear to be a need for such close proximity to safety systems (examples included plating located less than one inch from core spray and HPCI piping and scaffolding very close to recirculation seal pressure sensing lines).

- The inspector found a scaffold board wired across the stairwell in the northwest corner room. While the board did not contain a formal scaffold permit, an August 22 note was attached indicating that Operations and Fire Protection personnel had approved its placement for use on Sunday. The board had not been removed after Inservice Inspection activities were completed. The inspector immediately reported the issue to the Unit 2 control room and the board was removed. The inspector also discussed Assistant Unit Operator sensitivity to such issues with the Operations manager.

- Scaffold 2322 did not have the minimum clearance stated in the Appendix N evaluation. The inspector noted that some scaffolding tubing was very close to the torus on one end with the other end contacting a concrete wall. The engineering evaluation stated that members pointed at the torus should have at least 4 inches of clearance from the torus. This issue was immediately reported to the Unit 2 supervisor and the scaffold was removed later that evening. Problem Evaluation Report (PER) 971339 was initiated. The scaffold had been erected in February 1997 for work completed some time ago. Additionally, the Appendix M checklist was not filled out for this scaffold.

- Scaffold 2720 did not have a field engineer review documented on the tag. Step 7.11.8 of the TI appeared to require this. Scaffold 2733 had no expiration date on the tag.

- Scaffold 2575 was located very close to residual heat removal piping and instrument tubing associated with HPCI and recirculation pumps. A ladder for egress was located very close to 2-LPNL-925-0007B. The site engineering evaluation did not address all the clearance deviations noted. The inspector noted that conduit going to junction box 73-0111 appeared to have been bent as a result of being stepped on. The conduit was located in the path between the ladder to the scaffold.

- Scaffold 2657 had three spray cans sitting on it that could have fallen off. Additionally, the site engineering evaluation stated that a 1/2 inch minimum clearance should be maintained. However, some parts of the scaffold were closer than that to plant equipment.

- The inspector did not identify any of the scaffolds located such that it would adversely affect the operation of valves or electrical equipment. However, in several cases, the 2 feet minimum clearance (stated in the TI) from a valve handwheel was not met and Operations concurrence of the deviation was not documented.

The inspector noted that the scaffold inspections were consistently completed and documented as required by the TI.

On the evening of August 27, the Unit 2 support AUO identified that scaffolding had been erected (earlier that day) such that it was blocking air flow between the room cooler and the 2A residual heat removal pump. The scaffolding boards were removed and PER 971350 was initiated.

The deficiencies noted above appear related to two causes. There are weaknesses in portions of the procedural guidance for scaffolding erection, and supervisory personnel are not ensuring that procedural requirements are satisfactorily met.

Violation 296/96-04-07, Failure to Follow Procedural Requirements for the Installation of Scaffolding, was issued in May 1996. The violation had been caused by scaffolding constructed too close to the switch for an emergency diesel generator field flash breaker. This was the second time that a field flash breaker had been inadvertently operated during egress from a scaffold. Corrective actions to the first instance included requiring verification and documentation that the three foot clearance requirement was met in the 0-TI-248 checklist (Appendix M). Corrective actions for the second incident included counseling of scaffolding craft personnel on the clearance requirements. The inspection conducted this period indicated that the Appendix M checklist is not being rigorously completed. Several of the above noted problems involve noncompliance with the Appendix M checklist.

The number of deficiencies indicate that involved maintenance supervisors are not enforcing high standards of performance. There have been other incidents within the last year at Browns Ferry involving problems with oversight and accountability on the part of maintenance supervision. In May 1997, the NRC identified problems with implementation of Foreign Material Exclusion procedures. In August 1996, NRC inspectors identified poor oversight of painting activities on the Unit 3 emergency diesel generators. The licensee has identified examples of similar issues.

The deficiencies identified above are a violation of TS 6.8.1.1.a, in that procedures for performing maintenance that can affect safety related equipment were not implemented correctly. This issue is identified as Violation 260/97-09-02, Scaffolding Controls Not Properly Implemented.

c. Conclusions

The inspectors identified that the licensee was not properly implementing procedural controls over scaffolding. In some cases, scaffolds near safety related equipment were not constructed in accordance with limitations in the procedure or in the required engineering evaluation. The scaffolding assembly checklist was not being properly completed. Some procedural requirements, which would be difficult to complete, were not being implemented. No safety systems were rendered inoperable by the noted deficiencies. The inspectors concluded that the number and nature of the deficiencies indicate that supervisory personnel are not enforcing standards and failed to ensure that procedural requirements are satisfactorily met.

M1.2 Functional Testing of Snubbers

a. Inspection Scope (62707, 61726)

The inspectors noted that the licensee was performing functional testing of safety system snubbers as a pre-outage activity. The inspectors reviewed the applicable regulatory requirements, procedures, and work instructions.

b. Observations and Findings

On September 9, 1997, the inspectors noted that the licensee had removed a mechanical snubber (2-SNUB-063-5001) associated with the Unit 2 Standby Liquid Control (SLC) system from service to perform functional testing. The inspector was aware that the Unit 2 SLC system had been removed from service on September 7 for planned maintenance and returned to service on September 8. The detailed work schedule for the SLC inoperability period (referred to as a fragnet by the licensee) did not include the snubber testing. During the snubber work, the licensee entered a 72 hour limiting condition for operation and referenced TS 3.6.H.1. This practice had been implemented for snubber testing prior to recent refueling outages at Browns Ferry. Snubbers associated with the Unit 2 core spray and residual heat removal systems had also been tested prior to this outage.

The inspector reviewed Work Order (WO) 96-015749 which contained the work instructions for the testing. The inspector noted that the WO contained statements which indicated that the work was to be performed as a shutdown activity.

Technical Specification (TS) 4.6.H, which addresses functional testing of snubbers, states that "During each refueling outage, a representative sample of 10 percent of the total of each type of safety-related snubbers in use in the plant shall be functionally tested either in place or in a bench test." Additionally, the TS bases states that snubber operability tests shall be performed during refueling outages, at approximately 18-month intervals. The inspector concluded that the current Browns Ferry TS directed that functional testing of snubbers was

to be performed while the unit was shutdown. The inspector immediately informed maintenance management.

Mechanical snubber testing is performed in accordance with Procedure 2-SI-4.6.H-2A, Functional testing of Mechanical Snubbers (Revision 4). The inspector reviewed the procedure. Sections 1.2.2.2 and 1.3.1 contain statements which indicate that the testing is to be performed in a refueling outage. However, sections 1.3.2 and 3.2.8 indicate that the procedure can be performed in other than outage conditions for snubbers outside the drywell. The inspector concluded that the procedure did not exclude functional testing at times other than an outage.

Later on September 9, the licensee informed the inspectors that a review had been completed and it was determined that TS requirements had not been met regarding the snubber testing. The licensee's review identified 1980 guidance from the NRC indicating that the TS for functional testing of snubbers should indicate that the testing is to be performed while shutdown. The Browns Ferry TS for snubber testing was revised in 1982. The licensee indicated that a 10 CFR 50.73 report would be made addressing the issues.

At the September 10, 1997, Management Review Committee meeting, Problem Evaluation Report (PER) 971406 was reviewed. The PER addressed the snubber testing issue and was assigned to Operations for resolution. Snubber functional testing was stopped. Discussions with plant management indicated that the licensee was reviewing other maintenance activities to ensure that no similar TS noncompliances existed. Plant management also indicated to the inspector that the PER resolution would address the issue of the WO being worked at power although it was coded as a shutdown activity.

Functional testing of snubbers at other than refueling outage conditions is a violation of TS 4.6.H. This is identified as Violation 260/97-09-01, Functional Testing of Snubbers While Not in Refueling Outage Conditions.

c. Conclusions

The current Browns Ferry TS indicates that functional testing of snubbers is to be performed in a shutdown condition. The licensee was conducting the testing with the unit at power and on snubbers for systems required to be operable. Procedural controls for the testing did not enforce the TS requirements.

M1.3 Main Steam Line Tunnel Temperature Switch Test Heating Coil Adjustment

a. Scope (62707)

The inspector observed maintenance activities to adjust the test heating coil associated with main steam line tunnel temperature switch (TS) 3-TS-1-29C.

b. Observations and Findings

During testing on August 22, 1997, a test deficiency was identified on 3-TS-1-29C when the temperature switch failed to actuate during the performance of surveillance instruction 3-SI-4.2.A-f(A2), Main Steam Line Tunnel High Temperature Functional Test, Channel A2. Temperature switch 3-TS-1-29C was declared inoperable. The licensee determined that the test heating coil, used to actuate the temperature switch, needed to be adjusted to move the coil closer to the switch. On August 26, 1997, the inspector observed troubleshooting activities to adjust the test heating coil on temperature switch 3-TS-1-29C.

The inspector attended the prejob brief for the coil adjustment conducted in the control room. Since this evolution was considered high risk, the group discussed that no other testing would be performed which could cause a half scram while the activities were being accomplished. The group discussed that there would be a possibility of a half scram if the temperature switch is loose when the coil adjustment was made even though there was no indication that the switch was loose. The team considered numerous aspects of the job and the potential for problems to the extent that responders would be dressed and available to immediately attend to an injury in the high radiation area. The inspector considered that the licensee was well prepared for this task.

The inspector observed the coil adjustment from the video camera set up in the main steam tunnel. The Instrument Maintenance technician performed the adjustment as planned and swiftly with consideration for the high radiation area that was entered.

Following completion of the coil adjustment, the licensee performed surveillance instruction 3-SI-4.2.A-8FT(A2), Main Steam Line Tunnel High Temperature Functional Test, Channel A2, to meet the surveillance test interval requirement and to post maintenance test the temperature switch. The temperature switch actuated when the test pushbutton was depressed the fourth time. The procedure allows the test pushbutton to be depressed additional times to ensure that the temperature switch temperature is raised above the setpoint. The inspector noted that the procedure performance appeared to be slightly cumbersome. The Unit Operator identified some potential enhancements which he indicated would be submitted on a procedure validation review checklist. The temperature switch was declared operable on August 26, 1997.

M1.4 C3 EECW Pump Impeller Adjustment

a. Scope (62707)

The inspector observed maintenance activities to reset the pump impeller clearance on the C3 Emergency Equipment Cooling Water (EECW) pump.

The emergency diesel generator auto-started as designed. This LER is closed.

M8.2 (Closed) Licensee Event Report (LER) 260/96-002-00, Main Steam Isolation Valves Leak Rate Exceeded the Local Leak Rate Test Acceptance Criteria Due to Internal Component Wear. This LER was submitted as a voluntary LER for information only. On March 23 and 24, 1996, during a Unit refueling outage the "A" and "C" inboard main steam isolation valves (MSIVs) had a leakage that exceeded the local leak rate acceptance criteria of 11.5 standard cubic feet per hour (SCFH). The as-found leakage was 18.7 SCFH and 32.0 SCFH respectively. The cause of the leakage was determined to be misalignment of the valve mating seats caused by internal component wear. The "A" MSIV was changed to a long-nosed poppet to provide a guidance mechanism to improve the alignment on the mating seats. The valve was retested with a 6.1 SCFH as-left leakage. Only one long-nosed poppet was available and the "C" MSIV was repaired by lapping and cleaning. The "C" MSIV was retested with a 1.51 SCFH as-left leakage. The inspector reviewed the LER and Technical Specification (TS) surveillance requirement 4.7.A.2.i concerning MSIV leakage. The TS only requires that the valves be tested once each refueling outage. If leakage exceeds 11.5 SCFH, the valves must be repaired and retested until the leakage meets the acceptance criteria. The inspector concluded that the licensee's actions were in compliance with the TS. This issue has been a generic problem at Boiling Water Reactors. The licensee referenced previous LERs concerning this problem in this LER. This LER is closed.

M8.3 (Closed) Licensee Event Report (LER) 259/96-003-00, All Eight Plant Emergency Diesel Generators Unexpectedly Auto-Started From A Spurious High Drywell Pressure Signal. This event was discussed in Inspection Report 96-04. This event occurred during installation of wiring for the digital feedwater modification. A fault was introduced into the Emergency Core Cooling System (ECCS) logic while preparing wires for termination in panel 2-9-81. The fault caused a spurious high drywell pressure signal in the logic, which in combination with the existing low reactor pressure condition in Unit 2 resulted in the Engineered Safety Feature actuation. The licensee determined the root cause was inadequate work planning. The work plan was originally approved to be worked with panel 2-9-81 deenergized. The work plan was subsequently revised to work with the panel energized.

The inspector reviewed the licensee's incident investigation report for PER 960378. The licensee determined that as the outage schedule firmed up the panel would remained energized during the work. This would allow the panel work to proceed while maintaining ECCS equipment and their initiation logic available for required testing. Revisions were made to the work plan to delete the requirement for a clearance/isolation and a note was added to perform the work "hot." The work plan was never sent back to planning for review. At the time of the event the electrician was working alone inside the energized cabinet. As part of the corrective action the licensee was to change the administrative process for reviewing and rescoping of workplans when revisions are

b. Observations and Findings

On September 1, 1997, the licensee identified that the C3 EECW pump flow data taken during quarterly surveillance testing was below the minimum flow limit and the pump was declared inoperable. The licensee prepared a work order (WO) 97-008664-000 to adjust the impeller clearance. On September 3, 1997, the inspector observed the maintenance crew pre-job briefing and associated work. The brief was well conducted with focus on right train and component; personnel safety issues were addressed; general housekeeping and foreign material exclusion (FME) was discussed; and specifics of the step text work order were reviewed. The mechanical maintenance workers conducted the job using portions of MCI-0-023-PMP002, Emergency Equipment Cooling Water and Residual Heat Removal Service Water Pump (Byron Jackson Type KX) Disassembly, Inspection, Rework and Reassembly. The workers were knowledgeable of the task and the equipment.

M1.5 Replacement of 3-FCV-64-34 Solenoid Valve

a. Scope (62707)

The inspector observed the replacement of the solenoid valve in the control circuit for the 3-FCV-64-34 valve. The licensee determined that the failure of the 3-FCV-64-34 valve to close upon demand was due to the solenoid valve in the control circuit not operating properly.

b. Observations and Findings

On August 28, 1997, the inspector observed the replacement of the ASCO solenoid valve used to control the 3-FCV-64-34 valve. The repair evolution was well planned as a contingency if testing concluded that the ASCO solenoid valve was the cause of the 3-FCV-64-34 valve failures. The inspector did not identify problems with the maintenance work.

c. Conclusion

The inspector concluded that the maintenance work observed during the inspection period was generally well planned and worked. The inspector considered that ALARA planning of contingencies was good with regard to the high radiation evolution observed. A strong prejob brief was evident in preparation for C3 emergency equipment cooling water pump work.

M8 Miscellaneous Maintenance Issues (62707, 92902)

M8.1 (Closed) Licensee Event Report (LER) 259/96-002-00, An Emergency Diesel Generator Auto-Started Due To Undervoltage Condition As A Result of Personnel Error. This item was previously discussed in Inspection Report 96-04. The inspector reviewed the LER and the description of the event was the same as in the Inspection Report. This event was caused by a personnel error. Personnel involved in the test were disciplined.

made. Upon further review, the licensee determined that the existing procedural requirements were adequate and did not require revision. Site Standard Practice, SSP 6.2, Maintenance Management System, requires under step 3.5.2 that revisions to workplans be sent to planning for review. This was not followed. Since the procedure for control of workplans was not followed this was a violation of 10 CFR 50 Appendix B, Criterion V for failure to follow procedure. This non-repetitive licensee identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy. (NCV 50-260,296/97-09-04, Failure to Follow Procedure for Workplan Revision).

The inspector concluded that the incident investigation report was thorough and comprehensive. This LER is closed.

M8.4 (Open) Inspection Followup Item (IFI) 296/96-08-03, Unit 3 Main Steam Isolation Valve (MSIV) Circuitry Failures. Inspection Reports 96-05 and 96-08 describe NRC review of several MSIV limit switch failures and the licensee's corrective actions which included installation of temporary modifications. The inspector reviewed Revision 2 of Problem Evaluation Report (PER) 96-0083. During the most recent Unit 3 refueling outage, the problem was traced to damaged insulation on conductors in Conax conduit assemblies and the situation was corrected. It was concluded that the Kapton insulation on the conductors was damaged because heat shrink polyolefin tubing had not been installed on the inboard conductors during installation. The PER noted that NRC Information Notice (IN) 88-89 addressed this concern. The inspector reviewed the IN and noted that it specifically addressed the use of the polyolefin tubing to mechanically protect Kapton insulation. The licensee attributed the failure to install the heat shrink to a lack of specific guidance in work and vendor documents and workers not understanding some of the instructions. Similar maintenance activities have been completed in the past properly. The licensee implemented corrective actions to ensure workers will understand the importance of installing the heat shrink on the inboard conductors. The licensee determined that a total of 69 similar seals exist on Unit 3 and has selected 10 percent (7) of these seals to inspect during the upcoming outage to determine if heat shrink was applied to the inboard conductors. No similar failures have occurred on Unit 2. Pending results of those inspections, the IFI remains open.

M8.5 (Closed) Violation 296/96-04-07, Failure to Follow Procedural Requirements for Installation of Scaffolding. Section M1.1 describes NRC inspection of scaffolds in the Unit 2 reactor building. Numerous deficiencies were identified and cited as Violation 260/97-09-02. Additional reviews of scaffolding controls will be performed as followup to Violation 260/97-09-02. Violation 296/96-04-07 is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 RHRSW/EECW Pump Flow Test Data Used for In-Service Testing Trending

a. Scope (37551, 61726)

The inspector questioned flow data used to support In-Service Test trending on the residual heat removal service water and emergency equipment cooling water (EECW) pumps.

b. Observations and Findings

The licensee performs a quarterly flow test by adjusting discharge pressure to 135 psig and reading mV from an input to a flow modifier. The mV reading is then used in a calculation to determine the flow in gpm. The C3 EECW pump trend curve shows what appear to be comparable test results for flow over several quarterly tests until the September 1, 1997, test which shows that the pump is in the inoperable range due to low flow. A recent decrease in flow during testing of the B3 EECW pump again represents potential inaccuracies in pump testing methodology. The B3 EECW pump was replaced with a new stainless steel impeller and tested with flow very near the original baseline. Twelve days later, the pump flow tested approximately 200 gpm lower and put the pump in the alert range which required increased frequency testing. Based upon review of the examples identified and discussion with the licensee, the inspectors determined that pump testing allowed inaccuracies in the flow determination. The licensee indicated that they would pursue more repetitive methods of obtaining mV data for the flow calculation.

c. Conclusions

Based upon review of the examples identified and after discussion with the licensee, the inspectors concluded that the pump testing was limited in its repeatability. The inspectors will review the licensee's actions under Inspection Followup Item (IFI) 50-260,296/97-09-07, RHRSW/EECW Pump Flow Testing Issues.

E2 Engineering Support of Facilities and Equipment

E2.1 Pressurization of Shutdown Cooling Suction Piping

a. Scope (37551, 71707)

The inspectors reviewed and monitored the licensee's actions regarding pressurization of portions of the Unit 2 shutdown cooling suction piping. Apparently, a very small amount of reactor coolant leakage past the shutdown cooling isolation valves (2-74-47 and 48) was causing the suction piping to pressurize to above 100 psig.

b. Observations and Findings

In August, the licensee became aware that a slow pressurization of portions of the shutdown cooling (SDC) suction piping outside the containment isolation valves was occurring. Annunciator 2-XA-55-3E, window 32,"RHR SYS I/II DISCH OR SD CLG HDR PRESS HIGH" began to alarm once every several hours.

The annunciator was alarming due to pressure switch PS-74-93 sensing 100 psig. This pressure switch senses shutdown cooling piping pressure between the outboard SDC suction containment isolation valve and SDC suction isolation valves located near the RHR pumps. The control room operators complied with the alarm response procedure which included actions per section 8.30 of Operating Instruction OI-74 alarm response procedure. These actions included venting/draining the line from inside the drywell access area to reduce the pressure. There is a relief valve (74-659) located on the line which is set to relieve pressure at 150 psig. Due to the potential safety significance of the condition, the inspectors monitored the licensee's actions closely.

The licensee classified the issue as an operator work around and repetitive alarm issue. Significant engineering and management attention was applied to investigation of the condition. The inspectors met with licensee management and engineers several times during the report period. Since the licensee's leakage estimate via calculation appears to be well within local leakrate testing limits, the inspectors focused on verification that the licensee was adequately pursuing the problems while plant conditions were such that the leak was present. Completed and planned actions discussed included:

- After assuring that procedures would cause the SDC suction piping to be refilled prior to it being placed in service, the licensee revised section 8.30 of OI-74 such that a larger volume of the SDC suction line was drained in response to the annunciator. The drain point was moved to a fuel pool cooling system connection in the corner room above the RHR pumps. This increased the interval between draining evolutions from several hours to several days. The inspectors walked down the revised procedure flowpath and identified no significant problems.

- The licensee confirmed that the Unit 2 SDC suction relief valve (74-659) had a 150 psig setpoint and was tested satisfactorily in 1993. The licensee also intends to test the relief valve during the upcoming refueling outage. Controlled drawings indicate that the SDC piping is rated for 150 psig outside the containment isolation valves.

- Engineers obtained temperature measurements on the piping and conducted other diagnostic reviews. Previous local leakrate testing of the 74-47 valve (outboard isolation) indicated that the leakage was 0 standard cubic feet per hour. The acceptable

leakrate of the 74-47 by Appendix J requirements would be a small fraction of a gallon per minute of water (20 standard cubic feet per hour air). The 74-47 also fulfills a pressure isolation function. Acceptable leakrate for that function (1/2 capacity of relief valve) would be 10.5 gpm. The licensee's estimate of the present leakrate was done by calculation and indicated that it is less than these limits.

- The licensee initiated a Work Order to apply additional torque to the handwheel of valve 74-47 to seat the valve better. The torque will be limited to ensure that the motor operator will still operate that valve if needed. The additional torquing had not been implemented at the close of the inspection period since the revised draining method significantly increased the time intervals between increased pressure indications. During the outage, the torque switch setting of the 74-47 valve is scheduled to be increased as a Generic Letter 89-10 enhancement.

- The licensee discussed the issue with similar facilities in order to determine available means of resolution.

- Technical Support developed a resolution plan which includes installation of pressure recording instrumentation and additional temperature measurements. Refueling outage contingencies being considered include a modification to install a controlled leakoff line which could be used to port leakage back to the torus.

c. Conclusions

The inspectors concluded that the licensee was pursuing the problem in a reasonable manner and the present conditions do not represent an immediate safety concern. Licensee management has indicated that the intent is to effectively address the issue such that it will not exist once the unit is returned to power after the refueling outage.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) LER 296/96-004-00, LER 296/96-004-01, LER 296/96-004-02, and LER 296/96-006-00, Loss of the Emergency Core Cooling Systems (ECCS) Division I and Division II Instrumentation Renders ECCS Equipment Inoperable. These four LERs addressed failures of the ECCS inverters which occurred in 1996 due to failures of silicone rectifiers and a shorted commutation capacitor. Inspection Followup Item (IFI) 296/96-08-02, ECCS Inverter Failures, addressed these problems. Detailed inspector review and closeout of the IFI is addressed in Section E8.1 of Inspection Report 97-07. The LERs are closed.

E8.2 (Closed) Licensee Event Report (LER) 296/96-003-00, Unit 3 Scram On Low Reactor Water Level Due To Failure Of The Steam Packing Exhauster Bypass Flow Control Valve. This event was discussed in Inspection Report 96-05. The initiating event for this scram was the valve shaft failure of the steam packing exhauster bypass flow control valve, 3-FCV-2-190. The

valve failed close causing reduced condensate flow and tripping of feedwater and condensate booster pumps. This resulted in low reactor water level and a reactor scram. The cause of the valve failure was due to a material defect in a notched sensitive area. The licensee replaced the air operated valve with a manual valve following the event. The inspector reviewed the Inspection Report and LER. The inspector looked at the valve in the plant and the valve had been replaced with a motor operated valve. This LER is closed.

E8.3 (Closed) Licensee Event Reports (LERs) 260/96-004-00, 260/96-004-01, 260/96-008-00, 260/96-008-01 and 260/95-003-02, Main Steam Safety/Relief Valves Exceeded the Technical Specifications Required Setpoint Limit as a Result of Disc/Seat Bonding. All of these LERs concern the same issue of setpoint tolerance drift. Setpoint drift is a generic concern in Boiling Water Reactors using Target Rock Two-Stage Safety Relief Valves (SRVs). The cause has been attributed to corrosion bonding of the SRV pilot disc/seat interface resulting in drifting of the SRV setpoints. The licensee had previously implemented a BWR Owners Group recommendation for 3 of the 13 SRVs. This recommendation was to replace the SRV cartridges with cartridges that have a platinum alloyed stellite pilot disc. However, test results showed that the SRVs with the platinum alloyed stellite discs experienced setpoint drift comparable to the SRVs with stellite discs. Therefore the licensee is continuing with long term corrective action to resolve this issue. The licensee's analysis for a limiting pressurization transient concluded that even if four SRVs completely failed to open and the remainder operated at ten percent above setpoint a safety limit would not be exceeded. Although the conditions reported in the LERs were conditions outside Technical Specification they were bounded by analysis. In LER 296/97-003-00 concerning the same issue for Unit 3, the licensee discussed installing pressure switch actuation for the SRVs. This modification has successfully been installed at another facility. This modification is planned for Unit 2 during the next refueling outage. Additional actions are being evaluated in connection with the Boiling Water Reactors Owners Group. LER 296/97-003-00 remains open to track final resolution of this issue. The previous LERs are closed.

E8.4 (Closed) Unresolved Item 260/97-07-04, Failure of Fuel Pool Cooling Pump. This item addressed the failure of the 2B fuel pool cooling pump due to cavitation. IR 97-07 describes NRC review of the event. The inspector reviewed Problem Evaluation Report (PER) 970946 which addressed this issue. The inspector concluded that the licensee's corrective actions sufficiently addressed all the deficiencies associated with the incident. The inspector questioned the scheduled completion dates (August 1999) for Site Engineering to issue design changes to prevent fuel pool cooling pump cavitation when the demineralizer bypass valves opened. Subsequently, the inspector was informed that management intends to implement the design changes sometime after the Unit 2 refueling outage, most likely during the late fall or winter months. As noted in IR 97-07, the system engineer and his supervisor failed to initiate a PER on the cavitation problem when

are that a PER be initiated on such an incident. This non-repetitive, licensee identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy. NCV 260/97-09-05, Failure of Fuel Pool Cooling Pump. The unresolved item is closed.

E8.5 (Closed) Unresolved Item URI 50-260/97-08-02, Incorrect Oil Used in Two EDGs. The URI addressed 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 immediate corrective actions to drain and refill the oil in the 2A and 2D EDGs were discussed in NRC IR 97-08. After replacing the oil, the zinc content values for the two EDGs were substantially decreased; however, the zinc content was still above the required level. Subsequent actions included partially draining and refilling the 2A and 2D EDGs in an attempt to decrease the zinc content further. The licensee is actively pursuing the higher than allowed zinc levels.

In March 1997, problem evaluation report (PER 970563) was initiated to address a third party audit finding that "engineering component testing program weaknesses could delay resolution of known equipment problems and result in equipment problems not being identified prior to failure." This included that "the lubricating oil analysis results are not reviewed or trended...as an aid in predicting equipment performance." Corrective actions for the identified problem are not complete.

On September 11, 1997, the licensee briefed the inspector on current plans to upgrade the program to track lube oil samples. The Plan of the Day meeting materials will have a status of the oil samples once per week. The licensee has also named a point of contact on site for the lube oil analysis program. Currently, the licensee is using chemistry instruction (CI) CI-130, Diesel Fuel and Lube Oil Monitoring Program, to implement the lube oil program; however, the licensee plans to incorporate lube oil guidance into Technical Instruction (TI) TI-230. Additional planned corrective actions include establishing criteria for each component which will be incorporated into the procedure and personnel training in performing evaluation of lube oil analysis results. The corrective actions are planned for implementation by December 19, 1997. The inspector concluded that the planned corrective actions are adequate.

This non-repetitive licensee identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy. The failure of the licensee to identify that zinc additive oil had been put in the 2A EDG which led to the incorrect oil also being put into the 2D EDG approximately four months later is identified as Non-Cited Violation (NCV) 50-260/97-09-03, Incorrect Oil Used in Two EDGs.

IV. Plant Support

S3 Security and Safeguards Procedures and Documentation

S3.1 Security Program Plans

a. Inspection Scope (81700)

The inspector reviewed appropriate chapters of the licensee's Physical Security Plan (PSP) and Safeguards Contingency Plan (SCP), Revision 1, dated October 19, 1995; Revision 2, dated February 29, 1996; Revision 3, dated May 13, 1996. The inspector also reviewed Revision 21, dated April 14, 1995, and Revision 22, dated December 28, 1995, of the Security Personnel Training and Qualification (T&Q) Plan and security procedures as listed in paragraph S3.1(b).

b. Observations and Findings

Review of the changes submitted to the NRC in Revision 1, 2, and 3, of the PSP and Revisions 21 and 22 of the T&Q Plan for approval verified that the PSP and T&Q changes as submitted were in compliance with the requirements of 10 CFR 50.54(p). The PSP changes were mostly administrative in nature with the exception of Revision 3, of the PSP which deleted the security requirements during the security upgrade project. The PSP changes were well written and did not require any additional clarification. Physical Security Instruction Manual (PSIM), Section 105, was reviewed and considered acceptable as guidance to implement the licensee's compensatory measures for inoperative active vehicle barriers. The procedure required that inoperative active barriers be compensated for within 10 minutes. Section 105, of the PSIM guidance stated that "a vehicle of at least 3 tons or higher be provided in front of a non-functioning active vehicle barrier." Additionally, the inspector reviewed PSIM, Section 105, Security Testing and Maintenance and found the licensee had included the proper testing and maintenance requirements.

c. Conclusion

A random review of plans, records, reports, and interviews with appropriate individuals verified that security plan and procedures changes did not decrease the effectiveness of the PSP. The inspector reviewed Revision 1, 2, and 3, to the PSP and Revision 21 and 22 of the T&Q Plan and concluded that the PSP and T&Q Plan changes as submitted, met the requirements of 10 CFR 50.54(p). There were no violations of regulatory requirements noted in this area.

S6 Security Organization and Administration

S6.1 Management Support

a. Inspection Scope (81700)

The inspector evaluated the degree of the licensee's management support to the Physical Security Program. Based on the requirements contained in the PSP, the inspector reviewed the licensee's Safeguards Event Log (SEL) entries. This review was to determine if the licensee appropriately assigned, analyzed, and set priorities for corrective action for the reports and log entries, and whether the corrective action taken was technically adequate and timely.

b. Observations and Findings

The licensee had an on-site physical protection system and security organization. Their objective was to provide assurance against an unreasonable risk to public health and safety. The security organization and physical protection system were designed to protect against the design basis threat of radiological sabotage as stated in 10 CFR 73.1(a). A proprietary security force provided site security for the licensee. At least one full-time manager of the security organization was always on-site. This individual had the authority to direct the physical protection activities of the organization. The management system included a mechanism for establishing, maintaining, and enforcing written security procedures. Licensee management exhibited an awareness and favorable attitude toward physical protection requirements. This was evident by the support that security was provided in preparation for the Operational Safeguards Response Evaluation (OSRE) which was successfully completed on May 8, 1997, and the continued outstanding maintenance and engineering support to maintain and enhance security equipment.

The review of the SELs as of June 1997 indicated the following:

EVENTS	4th Quarter '96	2nd Quarter '97	1st Quarter '97
Human Errors	12 (11%)	03 (5%)	15 (17%)
Hardware Systems	97 (88%)	54 (95%)	74 (83%)
Other Events	0	0	0
TOTALS	109 (100%)	57 (100%)	89 (100%)

Each quarter had an excellent Trending Summary report that was provided to site management.

There were no long term compensatory measures in effect at the time of the inspection. Review of previous compensatory measures indicated that the licensee had 2219 hours of compensatory measures in FY 1996. Most of the compensatory measures were in support of planned outage of equipment to support operations. Review of the outstanding security work-orders revealed the following:

- 0 High Priority orders
- 0 Medium Priority
- 19 Low Priority

Of the 19 outstanding security work-orders, none involve regulatory requirements.

c. Conclusion

The inspector found that licensee management provided appropriate and excellent support for the Physical Security Program. Examples of the excellent management support were the support in preparation for the OSRE and the continued engineering and maintenance support to maintain the security equipment in a high state of readiness. Additionally, as another enhancement the licensee is installing a lightning dissipation system to greatly eliminate lightning from striking the security and plant monitoring equipment. There were no violations of regulatory requirements noted in this area.

S6.2 Effectiveness of Management Control

a. Inspection Scope (81700)

The inspector evaluated the adequacy of the licensee's controls for identifying, resolving and preventing problems by reviewing such areas as corrective action systems, root cause analyses, and self-assessment in the area of physical security. Also, this inspection was to determine whether there were strengths or weaknesses in the licensee's controls for the identification and resolution of the reviewed issues that could enhance or degrade plant operations or safety.

b. Observations and Findings

To determine the adequacy of the above, the inspector reviewed the licensee's SEL entries. This review was to determine if the licensee appropriately assigned, analyzed, and set priorities for corrective action for the reports and log entries, and whether the corrective action taken was technically adequate and timely.

The root cause analyses, corrective actions, and self-assessments, as mentioned in Paragraph S6.1, above and in Paragraph S7.1 below, were reviewed and found appropriate and adequate.

c. Conclusion

The inspector concluded that the licensee evaluated the non-human errors, hardware and mechanical problems and they were effectively controlled and managed.

S7 Quality Assurance in Security and Safeguards Activities

S7.1 Audits and Corrective Actions

a. Inspection Scope (81700)

Based on the commitments of the PSP, the inspector evaluated the licensee's audit program and corrective action system. This also ensured compliance with the requirement for an annual audit of the security and contingency programs. During the inspection, a small representative sample of the problems identified by audits was evaluated by the inspector to determine whether review and analysis were appropriately assigned, analyzed, and prioritized for corrective action and whether the corrective action taken was technically adequate and performed in a timely manner.

b. Observations and Findings

The licensee's program commitments included auditing its security program, including the Safeguards Contingency Plan, at least every 12 months. The audit included a review of routine and contingency security procedures and practices. This review evaluated the effectiveness of the physical protection system testing and maintenance program. This annual audit was completed on January 30, 1997, and the results are documented in audit report SSA-9617. The audit report was sent to the site Vice President and Corporate Management. Reports of audits were available for inspection at the plant for a period of three years. The auditors concluded that the security program continued to meet the regulatory requirements. In addition to the annual audits, the licensee had conducted audits of specific security practices and the audit findings were documented in NA-BF-97-01, dated January 27, 1997; NA-BF-97-11, dated February 25, 1997; NA-BF-97-23, dated March 31, 1997; NA-BF-97-35, dated May 6, 1997; and NA-BF-97-46, dated June 3, 1997.

c. Conclusion

Licensee-conducted audits were thorough, complete, and effective in terms of uncovering weaknesses in the security system, procedures, and practices. The last audit report concluded that the security program was effective. The licensee had acted appropriately in response to recommendations made in the audit report. The inspector determined that audit items were reviewed, appropriately assigned, analyzed, and prioritized for corrective action. The corrective actions taken were technically adequate and performed in a timely manner. There were no violations of regulatory requirements noted in this area.

S.8 Miscellaneous Security and Safeguards Issues (92904)

S8.1 (CLOSED) VIO 50-259,260,296/96-07-01, Failure to Properly Search Packages Entering the Protected Area. The inspector reviewed the licensee's lesson plan, personnel and package search enhancement, and the attendance roster and determined that all personnel had been retrained in proper search procedures as a result of the incident. The inspector reviewed search procedures during the inspection and concluded that personnel were searching packages and containers as required. The corrective action is considered adequate to close this violation.

S8.2 (CLOSED) IFI 50-259,260,296/96-07-02, Lighting Glare Prevents Adequate Assessment at the Intake Structure. The licensee's corrective actions included re-positioning and refocusing of cameras 25a and 25b, and hoods were placed on the cameras to prevent rain from landing on the lens and to shield direct light from the cameras. Also, the light bulbs on the handrail were changed to non-glare bulbs, and the lens on the high mast lights were repositioned to reduce glare. The inspector determined that the corrective actions were adequate to close this IFI.

F2 Status of Fire Protection Facilities and Equipment

a. Inspection Scope (71750, 62707)

The inspector observed performance of section 7.2.8 of 0-SI-4.11.B.1.C, High Pressure Fire Protection System Flushes. This section addressed portions of the Unit 2 reactor building preaction sprinkler system. In addition to assessing the conduct of the test, the inspector examined the strainer basket to determine if excessive quantities of corrosion products or other materials were entering the fire protection system.

b. Observations and Findings

The work was completed according to the work instructions. The procedure was actively utilized and the workers were knowledgeable of the evolution. Radio communications were appropriately formal. The workers were careful when draining the system to minimize overflow of the floor drain. Second party and independent verification were performed in accordance with requirements. The workers were cautious when re-opening isolation valves.

The procedure directed that fire protection water be flushed (from the outside loop header into the reactor building and through the strainer) for at least 10 minutes. The strainer basket was then inspected. The inspector observed that the strainer contained only a thin film of minute particles which could be easily wiped off. There was not any accumulation of corrosion products or other river materials in the strainer or housing. This indicated that the licensee's processes for the raw water fire protection system are adequately protecting the system. IR 97-07 described programmatic review of the licensee's program to maintain the reliability of the fire protection raw cooling water system.

R4 Staff Knowledge and Performance in Radiological Controls and Chemistry

R4.1 High Radiation Area Doors

a. Inspection Scope (71750)

During the inspection period, the inspectors verified that locked high radiation areas were maintained in accordance with the licensee's procedural guidance.

b. Observations and Findings

During tours of the facility, the inspectors checked numerous locked high radiation area doors to verify that the doors were maintained locked. No problems were identified.

V. Management Meetings

X1 Exit Meeting Summary

The resident inspectors presented inspection findings and results to licensee management on September 17, 1997. Other formal meetings to discuss report issues were conducted on August 15 and September 8.

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
D. Nye, Site Engineering Manager
K. Singer, Plant Manager
J. Schlessel, Acting Maintenance 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 81700:	Physical Security Program for Power Reactors
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	50-260/97-09-01	Open	Functional Testing of Snubbers While Not in Refueling Outage Conditions (Section M1.2)
VIO	50-260/97-09-02	Open	Scaffolding Controls not Properly Implemented (Section M1.1)
NCV	50-260/97-09-03	Closed	Incorrect Oil Used in Two EDGs (Section E8.5)
NCV	50-260,296/97-09-04	Closed	Failure to Follow Procedure for Workplan Revision (Section M8.3)
NCV	50-260/97-09-05	Closed	Failure of Fuel Pool Cooling Pump (Section E8.4)
URI	50-296/97-09-06	Open	Actions for Inoperable Containment Isolation Valve (Section O1.1)
IFI	50-260,296/97-09-07	Open	RHRSW/EECW Pump Flow Testing Issues (Section E1.1)

DISCUSSED

Type	Item Number	Status	Description and Reference
IFI	296/96-08-03	Open	Unit 3 Main Steam Isolation Valve (MSIV) Circuitry Failures (Section M8.4)

CLOSED

Type	Item Number	Status	Description and Reference
LER	296/96-002-00	Closed	Unit 3 Scram Following Loss Of Reactor Feedpump 3C (Section O8.1)
VIO	296/96-12-01	Closed	Failure to Ensure Proper Position of EDG Aux Board Room Exhaust Fans (Section O8.2)
VIO	296/96-13-03	Closed	Uncontrolled Locked High Radiation Area (LHRA) (Section O8.3)
LER	259/96-002-00	Closed	An Emergency Diesel Generator Auto-Started Due To Undervoltage Condition As A Result of Personnel Error (Section M8.1)
LER	260/96-002-00	Closed	Main Steam Isolation Valves Leak Rate Exceeded the Local Leak Rate Test Acceptance Criteria due to Internal Component Wear (Section M8.2)
LER	259/96-003-00	Closed	All Eight Plant Emergency Diesel Generators Unexpectedly Auto-Started From A Spurious High Drywell Pressure Signal (Section M8.3)
VIO	50-296/96-04-07	Closed	Failure to Follow Procedural Requirements for Installation of Scaffolding (Section M8.5)
LER LER LER LER	296/96-004-00 296/96-004-01 296/96-004-02 296/96-006-00	Closed	Loss of the Emergency Core Cooling Systems (ECCS) Division I and Division II Instrumentation Renders ECCS Equipment Inoperable (Section E8.1)
LER	296/96-003-00	Closed	Unit 3 Scram On Low Reactor Water Level Due To Failure Of The Steam Packing Exhauster Bypass Flow Control Valve (Section E8.2)
LER	260/96-004-00 260/96-004-01 260/96-008-00 260/96-008-01 260/95-003-02	Closed	Main Steam Safety/Relief Valves Exceeded the TS Required Setpoint Limit as a Result of Disc/Seat Bonding (Section E8.3)

URI	260/97-07-04	Closed	Failure of Fuel Pool Cooling Pump (Section E8.4)
URI	260/97-08-02	Closed	Incorrect Oil Used in Two EDGs (Section E8.5)
VIO	259,260,296/96-07-01	Closed	Failure to properly search packages (Section S8.1)
IFI	259,260,296/96-07-02	Closed	Lighting glare hampered assessment at intake structure (Section S8.2)