

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos: 50-259, 50-260, 50-296
License Nos: DPR-33, DPR-52, DPR-68

Report Nos: 50-259/98-05, 50-260/98-05, 50-296/98-05

Licensee: Tennessee Valley Authority

Facility: Browns Ferry Nuclear Plant, Units 1, 2, & 3

Location: Corner of Shaw and Browns Ferry Roads
Athens, AL 35611

Dates: July 12 - August 22, 1998

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(Sections E8.1-8.4)
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(Section E8.7)

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Enclosure 1

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EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Units 1, 2, & 3
NRC Inspection Report 50-259/98-05, 50-260/98-05, 50-296/98-05

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection and inspection by a Project Engineer. In addition, the report includes in-office inspection of the motor operated valve program (Generic Letter 89-01) implementation.

Operations

- Fuel receipt inspections were performed effectively and demonstrated good attention to detail (Section 01.1).
- Following implementation of the Improved Technical Specifications, the licensee identified a mispositioned damper, resulting in the inoperability of a Unit 3 Control Room Air Conditioning Unit (Section 01.2).
- The licensee identified that a high steam dome pressure indication was not effectively evaluated to determine necessary corrective measures, as required by procedures, when the steam dome pressure was recorded and determined to be outside of the TS-required acceptance criteria (Section 04.1).

Maintenance

- Maintenance work activities were performed in a professional and thorough manner (Section M1.1).
- Effective troubleshooting by licensee engineers determined the cause of an oil foaming problem with the Unit 3 Reactor Core Isolation Cooling System. Troubleshooting activities were well-planned and executed with reliable maintenance support (Section M1.2).

Engineering

- The licensee identified that the rod block monitor was inoperable due to an incorrect potentiometer setting (Section E2.1).
- The inspector identified that the surveillance procedures for functional testing of the residual heat removal loop I/II valve logic and interlocks was inadequate (Section E8.5).
- The licensee met the intent of Generic Letter 89-10 (Section E8.7).



Plant Support

- New fuel receipt surveys were thorough and performed by knowledgeable radiological technicians (Section R4.1).
- The protected area was well lit and temporary structures had sufficient temporary lighting (Section S2.1).



Report Details

Summary of Plant Status

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

Unit 2 operated at or near full power with the exception of planned power decreases. Additionally, on July 30, power was decreased approximately five percent to perform backwashing of demineralizers with one demineralizer out of service due to resin trap problems. On August 2, during control rod drive exercises, power was decreased to approximately 70% to facilitate testing following repair of a directional control valve associated with control rod 14-35.

Unit 3 began coastdown for the U3C8 outage on July 21. Planned power decreases were also performed to implement final feedwater reduction activities.

I. Operations

01 Conduct of Operations

01.1 Unit 3 New Fuel Receipt Inspection (71707, 62707)

During the inspection period the inspectors observed portions of new fuel bundle receipt inspections, which were ongoing throughout the inspection period. On July 22, 1998, the licensee fuel inspectors identified that a partial length fuel rod was not fastened to the bottom support plate. The partial length fuel rod was positioned at an interior location within the fuel bundle. The deficiency identification demonstrated good attention to detail by the licensee fuel inspectors (unlicensed operators). The licensee initiated a Problem Evaluation Report (PER) (BFNPER 98-008055) and contacted the fuel vendor. The inspectors observed the performance of fastening the partial length fuel rod to the bottom support plate on July 28, 1998. No problems were noted. No other significant discrepancies with new fuel bundles were noted by the licensee. The inspectors concluded that the fuel receipt inspections were performed effectively.

01.2 Unit 3 Control Room Air Conditioning System Inoperable Due to Mispositioned Damper

a. Inspection Scope (71707)

The inspectors reviewed the licensee's actions to correct a mispositioned damper which affected the operability of the Unit 3 control room air conditioning system.

b. Observations and Findings

On July 31, 1998, a licensee engineer identified that the Operations' lunch room damper 3-31-0105 was fully open. As-found testing determined that the flow to the lunch room was 741 cubic feet per minute (cfm) with Air Handling Unit (AHU) B in service. The licensee had previously set



the damper to a throttled position with AHU B in service and Control Room Emergency Ventilation System (CREVS) A running. This damper is set to ensure an acceptable flow of air to the Unit 3 control room, as required by the Technical Specifications (TSs). Surveillance Requirement (SR) 3-SR-3.7.4.1 (AIR), Control Room Air Conditioning System Performance, requires that the main control room AHU 3B deliver between 6503 and 7947 cfm to the Unit 3 control room when the control room is isolated.

On July 24, 1998, the licensee balanced air flow from AHU B, with CREV A in service, to the Unit 3 control room in preparation for implementation of the Improved Technical Specifications (ITS). Discussions with cognizant licensee personnel indicated that the flow data through the lunch room damper was comparable with or without CREVS in service. Data collected indicated that with the flow to the lunch room of 352 cfm, and the flow to the Technical Support Center (TSC) of 651 cfm, the resultant flow to the Unit 3 main control room was 6577 cfm. This value was within the requirements of the new ITS SR acceptance criteria. However, with the as-found flow of 741 cfm to the lunch room, the resultant flow to the Unit 3 control room, using the July 24 data, would have been less than that required by the ITS SR. Since the licensee had implemented ITS on July 27, 1998, the LCO was applicable when the condition was identified on July 31, 1998, and the LCO was appropriately entered and documented by control room operators.

The licensee readjusted the damper in the lunch room so that flow was within limits at 288 cfm. That value was determined to be acceptable by the licensee from the ventilation and air conditioning air flow drawing. The damper was controlled by an operator aid/permanent information posting (PIP) that was placed at the damper stating "DO NOT ADJUST DAMPER SET BY ITS SR 3.7.4.1 PIP98-010." The PIP was installed on July 23, 1998. 10 CFR 50, Appendix B, Criterion V, states, in part, that activities affecting quality shall be prescribed by documented instructions appropriate to the circumstances and shall be accomplished in accordance with these instructions. The instructions provided by the PIP were not accomplished and resulted in the inoperability of TS-controlled equipment.

The licensee's immediate corrective actions were to re-position the damper to restore the system to operable and initiate shiftly checks of the grill louver position. Additional corrective actions included briefing Operations crews on this event and its significance, and implementation of a design change that revised flow rates such that the lunch room damper can be full open. Other planned corrective actions included re-enforcing expectations of the crews' adherence to PIPs, labels, and other information postings, and establishing adherence to PIPs, labels, and other information postings as a focus area for the Operations self-assessment program for the month of September.



This non-repetitive, licensee-identified and corrected violation is identified as Non-Cited Violation (NCV) 50-296/98-05-01, Control Room ACU 3B Inoperable Due to Mispositioned Damper, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusion

During preparation for implementation of ITSs, the licensee performed air flow balancing to ensure that new TS requirements would be met. Following implementation of the new requirements, licensee engineers identified a mispositioned damper which caused the flow to the control room to be below that required with the 3B air conditioning unit in service. The damper was controlled with a permanent information posting (PIP) in place on the damper. The instructions provided by the PIP were not followed, resulting in the inoperability of TS-controlled equipment.

01.3 General Comments

While performing a review of Unit 1 Reactor Building Log readings from the Assistant Unit Operator (AUO) rounds database, the inspectors noted several minor discrepancies in the "Notes" sections. These discrepancies were discussed with Operations management and a PER was generated. AUO attention to detail has been identified as a challenge to the licensee in past NRC assessments and inspection reports. The licensee is aggressively pursuing improvements through the use of an AUO "hit" team to address management-identified challenges and objectives.

04 Operator Knowledge and Performance

04.1 Reactor Vessel Steam Dome Pressure Surveillance

a. Scope (71707, 61726)

The inspectors reviewed the licensee's actions when reactor vessel steam dome pressure readings were found to be greater than the TS limit. This new SR was implemented by ITS SR 3.4.10.1.

b. Observations and Findings

On July 27, 1998, the licensee implemented the ITS. SR 2, Instrument Checks and Observations, contains the licensee's procedure to perform most 12-hour, 24-hour, and 7-day instrument checks and observations, as required by the TSs. TS SR 3.4.10.1 requires verification that reactor vessel steam dome pressure is ≤ 1020 pounds per square inch gage (psig) every 12 hours. This new TS requirement was implemented by the licensee in SR 2 by recording pressure as read on reactor vessel high pressure scram pressure indicating switches (PIS) located in the Units 2 and 3 auxiliary instrument rooms (2&3-PIS-3-22AA, 2&3-PIS-3-22BB, 2&3-PIS-3-22C, and 2&3-PIS-3-22D). The scale for the PIS's is 0-1200 psig with 20 psig increments. The accuracy of the indication is ± 36 psi (3% of scale), per licensee scaling documents.



As early as July 27, 1998, when the new ITS SR was implemented, pressure readings were recorded in SR 2 for Unit 3 that were in excess of the allowed limit. Similarly, Unit 2 pressure readings in excess of the allowed limit were recorded as early as July 30, 1998. The inspectors noted that there are various other pressure indicators in the control room which indicate reactor vessel steam dome pressure. Test deficiencies (TDs) were written in response to the high recorded values and a procedure change request was written to revise the instruments used. However, no other compensatory measures were taken until August 2, 1998, when operations personnel initiated a PER. Operations personnel also dispatched instrument mechanics to take voltage measurements from the PIS to determine pressure. Converting the measurements to pressure readings eliminated the inaccuracies in the PIS and resulted in pressure readings that were well within the limits of the TS requirement and more closely related to the other pressure readings available in the control room.

The licensee performed a review of reactor vessel steam dome pressure using more accurate data from the plant Integrated Computer System (ICS). This data showed that the TS pressure limit was not exceeded during the period of concern (July 27 through August 1, 1998). The situation was not effectively evaluated to determine necessary corrective measures, as required by Site Standard Practice (SSP) SSP-2.1, Site Procedures Program. Readings were still being recorded on SR 2 to meet the TS SR after the operators recognized that the required instrument values exceeded the acceptance criteria.

The licensee revised 2-SR 2 and 3-SR 2 to require data for reactor steam dome pressure to be taken from higher accuracy instrumentation. Management expectations for sensitivity to TS acceptance criteria and to TD review was re-enforced. For example, shift managers were directed to review all TDs for a 90-day period and all operations crews were scheduled to receive additional training in the area of TDs. In addition, Operations management had established TDs as a focus area for the Operations self-assessment program for the month of September. This non-repetitive, licensee-identified and corrected violation is identified as NCV 50-260; 296/98-05-02, Failure to take Appropriate Corrective Measures for High Steam Dome Pressure Indication, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusion

The licensee identified that a high steam dome pressure indication was not effectively evaluated to determine necessary corrective measures, as required by procedures, when the steam dome pressure was recorded and determined to be outside of the TS-required acceptance criteria.

08 Miscellaneous Operations Issues (92901)

08.1 (Closed) Licensee Event Report (LER) 50-296/98-002-00, Engineered Safety Features Actuation as a Result of a Switch Failure. This event was



discussed in Inspection Report (IR) 50-259, 260, 296/98-02. No new issues were revealed by the LER. This LER is closed.

- 08.2 (Closed) LER 296/98-003-00, Reactor Manually Scrammed to Prevent Thermal-Hydraulic Instability After Recirculation Pump Runback. This event was discussed in IR 50-259, 260, 296/98-02. No new issues were revealed by the LER. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

The inspectors observed portions of the following work activities:

- Containment Atmospheric Dilution Tanks A and B insulation space vacuum restoration and valve maintenance
- Unit 1 Reactor Zone Supply Fan Damper preventive maintenance
- Unit 3 High Pressure Coolant Injection (HPCI) System Test Return Valve (73-35) Operator corrective maintenance
- Unit 2 A H₂-O₂ Analyzer valve and instrumentation maintenance
- Unit 2 A Reactor Zone Exhaust Fan Damper Actuator corrective maintenance
- CREVS B 1.5 kV Space Heater Replacement

b. Observations and Findings

The inspectors found the work performed under these activities to be professional and thorough. The workers and supervisors were knowledgeable of the assigned tasks, as demonstrated by performance and responses to the inspectors' questions. Appropriate contractor control and good support from engineering was observed, where applicable. Appropriate radiation control measure were in place, when applicable.

The inspectors identified minor problems with the application of confined space entry requirements while work was performed on the CREV system. This issue was discussed with licensee management.

M1.2 Troubleshooting of Reactor Core Isolation Cooling (RCIC) System Oil Foaming Problems

a. Scope (62707, 37551)

The inspectors followed the licensee's investigation to determine the cause of oil foaming on the Unit 3 RCIC System. Troubleshooting and testing was observed by the inspectors.



b. Observations and Findings

On July 15, 1998, during performance of routine testing, the licensee identified a problem with the Unit 3 RCIC system. The symptoms included oil and foam discharging from the sump vent and high oil temperature alarms in the control room.

The licensee developed a troubleshooting plan and scheduling work plan (fragnet) to address the issue. The licensee's action plan was comprehensive and thorough. Following testing and troubleshooting activities, the licensee determined that the problem was due to a high oil level in the RCIC turbine bearing housing; the overspeed trip disc assembly was contacting oil in the sump and causing excessive aeration of the oil. The oil level was re-established in accordance with the vendor manual and testing was performed. The symptoms did not reoccur. The licensee determined that RCIC would have performed its safety function and run indefinitely with this condition. A level decrease, due to the loss of oil, would have eventually cleared the overspeed trip disc and agitation would have stopped. The inspectors determined that the troubleshooting activities were well planned and executed and were effective to determine the cause of the problem.

c. Conclusion

Effective troubleshooting by licensee engineers determined the cause of an oil foaming problem with the Unit 3 RCIC System. Troubleshooting activities were well-planned and executed with reliable maintenance support.

M8 Miscellaneous Maintenance Issues (62707, 92902)

M8.1 (Closed) Violation 50-296/97-12-02, Failure to Document Condition Adverse to Quality. This violation addressed an adverse condition that was not promptly documented and reported to the appropriate organization's Department Manager for evaluation and disposition. The inspector reviewed the licensee's corrective actions and determined that they were acceptable and that management expectations were communicated to the staff. This violation is closed.

III. Engineering

E2.1 Rod Block Monitor (RBM) Inoperable

a. Scope (37551)

The inspector reviewed the licensee's actions to troubleshoot symptoms associated with an inoperable RBM.

b. Observations and Findings

On August 16, 1998, during Unit 2 control rod drive exercise testing, control room operators identified that the RBM remained bypassed when an



internal rod was selected following the selection of an edge rod in the same rod group. Control rod testing was stopped and the problem was investigated. Additional troubleshooting determined that the RBM system was failing to perform a null sequence for rods that were selected within the same rod group. Detailed testing was performed by the licensee on the available Unit 3 mockup, which is planned for installation during the Fall 1998 outage. The licensee's vendor was also contacted for support. The licensee concluded that the setting of a potentiometer within the RBM interface module was the cause of the problem. On August 20, 1998, the licensee reset the identified potentiometer on the installed Unit 2 RBM. The post-maintenance testing verified the RBM to be functioning properly. Further detailed review of the root cause of the identified problem, the licensee's corrective actions, and the overall safety significance of the RBM inoperability will be addressed in Unresolved Item (URI) 50-260/98-05-04, Rod Block Monitor Inoperable.

E8 Miscellaneous Engineering Issues (92903 and TI 2515/109)

- E8.1 (Closed) LER 50-260/97-003-00, Field Measurements of the HPCI Turbine Speed Indicated Speed Was Lower than the Speed Displayed in Control Room. NRC IR 50-259, 260, 296/97-08 describes the NRC review of the event and describes the associated NCV 50-260/97-08-03. The event was attributed to an improper evaluation of the packing leak of HPCI steam admission valve 2-FCV-73-16 which eventually found its way into the unsealed junction box and caused spurious grounding of some of the HPCI cables. The corrective actions listed in the LER were completed. The LER is closed.
- E8.2 (Closed) LER 50-260/97-006-00, High Pressure Coolant Injection Inoperable as a Result of HPCI Turbine Inlet Steam Line Drain Pot High Level. The LER documented an event in which the licensee declared the Unit 2 HPCI system inoperable due to high water level in the HPCI turbine inlet steam line drain pot. The licensee's investigation of the incident was inconclusive. The licensee noted that during the previous refueling outage the HPCI turbine steam supply valve (2-FCV-73-16) had been replaced. The valve is located upstream of the drain pot. The replacement process had required a great deal of welding and grinding and the licensee surmised that the activity resulted in foreign material (metal and cutter material) entering the piping, resulting in a blockage of the 1-inch diameter discharge line. The licensee carried out extensive troubleshooting activities, including a visual inspection (using a boroscope) of accessible piping and a blowdown of the piping using water and air. Nothing was specifically found to be blocking the discharge line. Upon subsequent repressurization of the line to reactor pressure, the flow returned to that normally expected. The licensee concluded that the blockage had been dislodged. Discussions with licensee representatives determined that no problems with the drain pot level had been experienced since the troubleshooting activities. The licensee plans to replace the Unit 3 HPCI turbine steam supply valve during the upcoming outage in September using a modification package with instructions to ensure that the affected piping is properly



inspected for the introduction of foreign material. LER 50-260/97-006-00 is closed.

- E8.3 (Closed) LER 50-260/97-007-00, Reactor Scram Resulting from Pressure Perturbation in the Electro-Hydraulic Control System Caused by Testing No. 1 Turbine Control Valve. On October 28, 1997, at 3:09 p.m., Unit 2 automatically scrammed from approximately 70% power while cycling the No. 1 Turbine Control Valve after repair. Licensee investigation of the event determined that the scram resulted from an actuation of scram channel B1, caused by a pressure perturbation in the electro-hydraulic control (EHC) system at the turbine control valves. The pressure perturbation was induced by opening the No. 1 Turbine Control Valve. The pressure switch for the No. 2 Turbine Control Valve (which provides an input to the Reactor Protection System (RPS) logic when the pressure decreases below the setpoint, indicating control valve fast closure) was subjected to the pressure transient. Although the transient was of such a short duration that the pressure switch did not completely operate, the licensee postulated that the transient resulted in a decreasing voltage to the scram contactors' scram channel B1, causing one of the pair of contactors to drop out. A half scram was already present in Channel A (due to maintenance of the No. 1 Turbine Control Valve). When the B1 channel scram contactor dropped out, 93 control rods (in Groups 1 and 4) scrammed and one of the two backup scram valves operated, venting the scram pilot air header. The consequent drop in pressure in the scram pilot air header resulted in a full scram signal.

The licensee discussed this incident with the system's vendor, who recommended that the licensee install orifices in the EHC lines at the turbine control valves. The licensee planned to install the orifices during the next refueling outages for Units 2 and 3, in April 1999 and November 1998, respectively. The inspectors verified that the Unit 3 activities were planned to be done during the outage by reviewing the Final Draft Schedule for the Unit 3 Cycle 8 (U3C8) refueling outage. The orifice installation activities were clearly identified. Therefore, this LER is closed.

- E8.4 (Closed) LER 296/98-001-00, Computer Modeling Indicates Sensors May Not Detect All Pipe Breaks. On January 21, 1998, the licensee determined through the use of computer models that temperature sensors for certain high energy line breaks (HELBs) may not detect all possible break locations. The licensee's current analysis for Environmental Qualification (EQ) of electrical equipment is based on the MONSTER computer code, which is no longer commercially available. In support of a license amendment for a power uprate, the licensee used an updated code, Generation of Thermal-Hydraulic Information for Containments (GOTHIC). Due to differences in modeling and assumptions, the results were somewhat different. The GOTHIC code predicted that a postulated critical crack in the RCIC steam line in the main steam valve vault (MSVV) may go undetected under certain conditions. The licensee reconfirmed that the MONSTER code was properly utilized to establish the current EQ temperature parameters. Furthermore, the GOTHIC code included a degree of conservatism. Therefore, the licensee was unable



to conclusively determine that the leak detection and isolation would not occur as modeled by the MONSTER code. Discussions with the licensee's representative determined that the part of the RCIC steam line in question is scheduled to be modified (per Mod No. 40713301) from a 3-inch diameter line to a 4-inch diameter line in the upcoming Unit 3 outage, per Drawing Change Notice (DCN) T40713. This modification will eliminate the postulated critical crack from this part of the RCIC steam line. This LER is closed.

- E8.5 (Closed) LER 50-260/97-002-00. During Generic Letter 96-01 Review, Inadequate RHR Surveillance Instructions Were Discovered. These surveillance instructions (SIs) resulted in not fully testing residual heat removal (RHR) TS logic circuits. The root cause was personnel error in that the SIs were not properly revised. Licensee review of SIs requested by NRC Generic Letter (GL) 96-01, Testing of Safety-Related Logic Circuits, determined that SIs (Function Testing of RHR Loop I and Loop II Valve Logic and Interlocks) did not fully test all relay logic combinations. These surveillances are required to be performed every 18 months. Reactor low pressure (<230 psig) inputs to the recirculation pump discharge valve logic circuits were not properly tested. Specifically, the channel A and B RHR relay contacts which provide inputs to the logic circuits were not verified closed when their respective relays were energized. This condition existed for Units 2 and 3.

The licensee promptly entered a 24-hour TS Limiting Condition for Operation (LCO) due to missed surveillance testing on June 26, 1997 (discovery date). Work orders which tested the relay contacts were satisfactorily completed later that day. The licensee determined that the procedure deficiencies were introduced when the surveillances were revised (June 1992 for Unit 2 and September 1995 for Unit 3) to allow the performance of the test with the plant at pressures >230 psig in addition to a shutdown and depressurized condition. Training and experience review were also completed by the licensee for engineering personnel. The licensee planned to revise the affected SI prior to its next performance to ensure that the relay contacts were adequately tested.

On August 12, 1998, the inspectors performed a review the affected procedures (2/3-SR-3.3.5.1.6(CI/CII), Functional Testing of RHR Loop I/II Valve Logic and Interlocks) which were instituted by ITS. The inspectors found that appropriate changes to the procedure steps for performing the test at reactor pressures <230 psig were made. However, the inspectors found that the portion of the procedure which allowed testing at pressures >230 psig had apparently not been revised to test the relay contacts. The inspectors reviewed the canceled predecessor SIs [2/3-SI-4.3.B-45A(a)(I)/(II), 2/3-SI-4.3.B-45A(b)(I)/(II), 2/3-SI-4.3.B-45A(c)(I)/(II), and 2/3-SI-4.3.B-45A(d)(I)/(II)] and found that they also were not changed to test the relay contacts when reactor pressure was >230 psig. The inspectors noted that although surveillance



procedures were upgraded to reflect the transition to the ITS, the testing requirements were not changed by ITS. The licensee was informed of the inspectors' findings.

Licensee review of the affected procedures and control drawings concluded that the relay contacts (Units 2 and 3 contacts 3-4 of relays 10A-K90A, 10A-K91A, 10A-K90B, and 10A-K91B) were not tested by the procedure that performs the test at >230 psig. Both licensee and inspector review of the status of testing on Units 2 and 3 confirmed that both units have been adequately tested within the TS surveillance frequency of 18 months. Although the last test on Unit 2 was at pressures >230 psig using the inadequately revised test procedure, the work orders performed on June 26, 1997, to test relay contact operation, were within the required surveillance periodicity.

The procedures used to perform functional testing of RHR loop I/II valve logic and interlocks did not adequately test relay contacts 3-4 of relays 10A-K90A, 10A-K91A, 10A-K90B, and 10A-K91B with the reactor at pressures >230 psig. This is an apparent violation of TS 5.4.1.a, which requires written procedures to be established, implemented, and maintained for TS required surveillances. This issue is identified as apparent violation EEI 50-260, 296/98-05-03, Inadequate RHR Valve Logic and Interlock Surveillance, pending review of the licensee's corrective actions. This LER is closed.

- E8.6 (Closed) Inspection Followup Item (IFI) 50-260, 296/97-09-07, RHRSW/EECW Pump Flow Testing Issues. The inspector was concerned that the repeatability and effectiveness of the residual heat removal service water (RHRSW) and emergency equipment cooling water (EECW) pump flow testing could be improved. The data that was previously reviewed showed examples of decreased flow during testing that caused increased frequency testing or inoperability of the pumps. Two different causes produced the changes in pump flows. For the rebuilt pumps with new stainless steel impellers, the licensee determined that actual variations in pump flow were due to a reduction in the shaft length which caused an increase in impeller gap. This reduction in shaft length is attributed to the tightening of the joints between the shaft and shaft couplings. The licensee planned to change the post-maintenance test requirements for future pumps to require a recheck of the impeller gap following pump run in. The second cause of changed pump flows could be attributed to a change in impeller lift due to thermal expansion differences because of different materials used for the pump shaft and the columns. This would vary the pump flows as river temperature changed.

The licensee plotted data taken from the ICS which provided an average pump flow along with the normal SI data. The quarterly flow test SI adjusts discharge pressure to 135 psig and reads millivolts (mV) from an input to a flow modifier. The mV reading is then used in a calculation to determine the flow in gallons per minute (gpm). The ICS data points plotted reasonably close to the data taken by the SI and trended



similarly; therefore, the inspectors concluded that a problem did not exist with the repeatability of the testing in this case. This item is closed.

E8.7 (Open) IFI 50-260, 296/98-03-03. Justification of valve factor and rate of loading assumptions.

(Open) IFI 50-260, 296/98-03-04. Analysis of dc MOV stroke times based on GL 89-10 test data.

These two followup items were opened pursuant to the NRC's completion of a review of the licensee's implementation of GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." The first questioned the adequacy of the licensee's justification for the valve factor and rate of loading values that were assumed in calculating thrust requirements for certain motor-operated valves (MOVs). The second questioned whether the licensee had demonstrated that the direct current (dc) MOVs were capable of meeting stroke time requirements under design-basis conditions. NRC IR 50-259, 260, 296/98-03, transmitted June 16, 1998, requested the licensee to provide a written response summarizing the plans and schedule to resolve these items.

The licensee responded to these IFIs in a letter dated July 16, 1998. The letter provided additional information regarding the valve factors assumed, indicated plans to utilize data from another licensee to justify the rate of loading value, and stated that a quantitative analysis had been performed which demonstrated that the Browns Ferry dc MOVs were capable of performing their design-basis functions within specified stroke times. Based on the information and plans provided in that letter and on the results of previous NRC inspections, the NRC determined that the licensee met the intent of GL 89-10 at Browns Ferry. The two IFIs will remain open pending NRC review of the rate of loading data to be obtained by the licensee and review of the licensee's dc MOV stroke time analysis.

IV. Plant Support

R4 Staff Knowledge and Performance in RP&C

R4.1 New Fuel Receipt Radiological Survey Performance (71750)

New fuel receipt and inspections were ongoing throughout the inspection period. The inspectors periodically monitored the performance of radiological survey performance during inspections on the refueling floor. No concerns were identified. On August 9, 1998, the inspectors observed new fuel delivery to the reactor building. The inspectors found that the radiological technician performing the surveys was knowledgeable of the new receipt survey requirements. The inspectors observed thorough and consistent surveys during the delivery.



S2 Status of Security Facilities and Equipment

S2.1 Protected Area Lighting (71750)

On August 9, 1998, the inspectors performed a walkdown of protected area lighting and found that all areas were well lit. Confined spaces beneath permanent and temporary structures were found to have sufficient temporary lighting. The inspectors noted that a licensee initiative to reduce the amount of temporary lighting required was in progress. This has reduced the amount of temporary lighting required in the protected area. For example, the space below the office trailers on the southeast side of the protected area have been fitted with metal sheathing thus making them inaccessible and eliminating the need for temporary lighting.

V. Management Meetings

X1 Exit Meeting Summary

The resident inspectors presented inspection findings and results to licensee management on August 21, 1998. Additional formal meetings to discuss inspection findings were conducted on August 14, 1998.

PARTIAL LIST OF PERSONS CONTACTEDLicensee

T. Abney, Licensing Manager
 J. Brazell, Site Security Manager
 R. Coleman, Radiological Control Manager
 C. Crane, Site Vice President, Browns Ferry
 R. Greenman, Training Manager
 J. Johnson, Site Quality Assurance Manager
 R. Jones, Assistant Plant Manager
 R. Moll, System Engineering Manager
 G. Little, Operations Manager
 D. Nye, Site Support Manager
 D. Olive, Operations Superintendent
 R. Ryan, Engineering Manager
 J. Shaw, Design Engineering Manager
 K. Singer, Plant Manager
 J. Schlessel, Maintenance Manager

INSPECTION PROCEDURES USED

TI 2515/109: Inspection Requirements for Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance"
 IP 37551: Onsite Engineering
 IP 61726: Surveillance Observations
 IP 62707: Maintenance Observations
 IP 71707: Plant Operations
 IP 71750: Plant Support Activities



IP 92901: Follow-up-Plant Operations
 IP 92902: Follow-up-Maintenance
 IP 92903: Follow-up-Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-296/98-05-01	NCV	Control Room ACU 3B Inoperable Due to Mispositioned Damper Section 01.2)
50-260, 296/98-05-02	NCV	Failure to Take Appropriate Corrective Measures for High Steam Dome Pressure Indications (Section 04.1)
50-260, 296/98-05-03	EEI	Inadequate RHR Valve Logic and Interlock Surveillance (Section E8.5)
50-260/98-05-04	URI	Rod Block Monitor Inoperable (Section E2.1)

Closed

50-296/98-05-01	NCV	Control Room ACU 3B Inoperable Due to Mispositioned Damper Section 01.2)
50-260, 296/98-05-02	NCV	Failure to Take Appropriate Corrective Measures for High Steam Dome Pressure Indications (Section 04.1)
50-260/97-003-00	LER	Field Measurements of the HPCI Turbine Speed Indicated Speed Was Lower than the Speed Displayed in Control Room (Section E8.1)
50-260/97-006-00	LER	High Pressure Coolant Injection Inoperable as a Result of HPCI Turbine Inlet Steam Line Drain Pot High Level (Section E8.2)
50-260/97-007-00	LER	Reactor Scram Resulting from Pressure Perturbation in the Electro-Hydraulic Control System Caused by Testing No. 1 Turbine Control Valve (Section E8.3)

50-296/98-001-00

LER

Computer Modeling Indicates Sensors,
May Not Detect All Pipe Breaks
(Section E8.4)

50-296/98-002-00

LER

Engineered Safety Features Actuation
as a Result of a Switch Failure
(Section 08.1)



UNITED STATES
NUCLEAR REGULATORY COMMISSION

WASHINGTON, D.C. 20555-0001

August 24, 1998

MEMORANDUM TO: Loren R. Plisco, Director
Division of Reactor Projects
Region II

FROM: Frederick J. Hebdon, Director
Project Directorate II-3
Division of Reactor Projects III
Office of Nuclear Reactor Regulation

SUBJECT: REQUEST FOR TECHNICAL ASSISTANCE (TIA 97-026) REGARDING
REACTOR CORE ISOLATION COOLING SYSTEM STEAM SUPPLY
LINE STEAM TRAP PIPING FLAW - BROWNS FERRY NUCLEAR
PLANT UNIT 3 (TAC NO. MA0276)

By memorandum dated November 26, 1997, the Division of Reactor Projects, Region II, (DRP) requested the assistance of the Office of Nuclear Reactor Regulation (NRR) in determining the acceptability of the licensee's actions with respect to a steam leak caused by a through-wall crack in piping associated with a steam trap in the Browns Ferry Nuclear Plant, Unit 3 (BFN-3) Reactor Core Isolation Cooling (RCIC) system steam supply piping. The flaw was located in American Society of Mechanical Engineers (ASME) Code Class 2 piping.

Manual isolation valves were not closed for several hours after the flaw was found, but when the manual valves were closed the leak could not be isolated. Thus, to effectively isolate the leak, the operators would have had to close the RCIC steam line isolation valves and declare RCIC inoperable. However, the licensee did not consider Technical Specification (TS) 3.6.G.1.b to be applicable for conditions found at power, and that isolation of the RCIC steam line to isolate the leak did not seem appropriate from a risk perspective. The licensee determined that the flawed piping was part of the reactor coolant pressure boundary, completed an evaluation of the flaw, and subsequently repaired the piping in a reasonable time frame. However, questions regarding compliance with TS and the NRC Inspection Manual remain unresolved. Therefore, Region II submitted four (4) questions to the NRR staff that relate to details of the licensee's actions.

Question 1.

The licensee's position is that the requirements of TS 3.6.G.1.b are not applicable for conditions (such as this flaw) found at power. Is this correct?

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Answer: TS 3.6.G.1.b. states, "With the structural integrity of any ASME Code Class 2 or 3 equivalent component not conforming to the above requirements (TS 3.6.G.1), restore the structural integrity of the affected component to within its limits or isolate the affected component from all OPERABLE systems." This TS is applicable for conditions found at power, and this conclusion was also reached by NRC Regional Management for BFN 3. Specifically, TS 3.6.G.1 states that the structural integrity of Class 1, 2, and 3 components shall be maintained throughout the life of the plant which means under every condition (i.e., at power or not at power). Since the steam leak was non-isolable, even after shutting the available manual isolation valves, and the requirements of TS 3.6.G.1 could not be met, the requirements of TS 3.6.G.1.b were applicable.

Question 2.

If TS 3.6.G.1.b. is applicable, did the licensee's actions meet all of the requirements of the TS?

Answer: The licensee did not meet the requirements of TS 3.6.G.1.b that are stated in the answer to question 1 above. Several hours after the flaw was found, the licensee shut the manual isolation valves, but this action did not isolate the steam leak. To isolate the leak at this point the licensee would have had to shut the RCIC steam line isolation valves and declare RCIC inoperable. However, the licensee did not declare RCIC inoperable while pursuing repair options. The TS requires that a component be declared inoperable when the structural integrity cannot be restored within its limits; this was the case for approximately 2 days. While the TS does not address the time frame for isolating the affected component, Section 6.15 of NRC Inspection Manual Chapter 9900 clearly states that upon discovery of leakage from a Class 1, 2, or 3 component pressure boundary, the licensee should declare the component inoperable. The staff interprets *upon discovery* to mean *immediately*. The staff agrees that there appears to be no safety consequences associated with the licensee's actions. The Inspection Manual Chapter is discussed in more detail in the answer to Question 3.

Question 3.

Did the licensee's actions meet the expectations promulgated in Section 6.15 of NRC Inspection Manual Chapter 9900 regarding actions to be taken if a leak is discovered in a Class 1, 2, or 3 component?

Answer: The licensee's actions did not meet the expectations promulgated in Section 6.15 of Inspection Manual Chapter 9900 regarding actions to be taken if a leak is discovered in a Class 1, 2, or 3 component. Section 6.15 states that "If a leak is discovered in a Class 1, 2, or 3 component in the conduct of in service inspections, maintenance activities, or during plant operation, IWA-5250 of Section XI [of the ASME Code] requires corrective actions be taken based on repair or replacement in accordance with Section XI." Section 6.15 also states that "Upon discovery of leakage from a Class 1, 2, or 3 component pressure boundary (i.e., pipe wall, valve body, pump casing, etc.) the licensee should declare the component inoperable."



Instead of shutting the RCIC system steam isolation valves and declaring the system inoperable, the licensee opted to perform an evaluation while also pursuing repair options. RCIC was not taken out of service until the repair was performed – approximately 2 days after the source of the leakage was identified. Section 6.15 of Manual Chapter 9900 clearly states that the component should be declared inoperable upon discovery of leakage from the component pressure boundary. Although the repair was reasonably prompt, the Manual Chapter suggests that the delay in declaring RCIC inoperable is not acceptable regardless of the corrective actions that were pursued by the licensee. Licensee management based its decisions, in part, on a 1992 ASME Code interpretation. Code interpretations are not a part of NRC regulations or of the ASME Code. The NRC's position on ASME Code interpretations is discussed in more detail in the answer to Question 4.

Question 4.

While ASME Code interpretations are clearly not part of the Code, licensees utilize the information presented in the interpretations. It appears that there is conflict between several interpretations and the Inspection Manual guidance. Is it appropriate for these apparent disparities to be addressed and if so, have they been?

Answer: The licensee applied the information in a 1992 ASME Code interpretation to conclude that IWA-5250 did not apply because the flaw was not identified during in service inspection. Specifically, the Code interpretation indicated that IWA-5250 is not applicable during maintenance activities or plant operations, and that an operability determination should be performed as a result of identification of the leak. This Code interpretation conflicts with the guidance in Section 6.15 of Manual Chapter 9900.

Conflicts between Code interpretations and NRC requirements are addressed in the Technical Guidance of Part 9900, and in the proposed rule change to 10 CFR 50.55a.

As stated in the Technical Guidance of Part 9900, "ASME Code interpretations are not incorporated into the Code of Federal Regulations and, therefore, the NRC is not bound by these interpretations." The guidance goes on to state that "While the NRC acknowledges that the ASME is the official interpreter of the Code, the Regulations transcend the Code. Since Code interpretations are not part of the regulations, licensees should exercise caution when applying interpretations to their facilities.

The proposed rule change to 10 CFR 50.55a highlights the fact that since interpretations are issued after the provision that it refers to, it can affect the NRC's understanding of the Code Editions and Addenda that are incorporated by reference into the regulations. The proposed rule change also notes that, in some cases, Code interpretations have been issued that conflict with NRC requirements, and these cases resulted in enforcement actions. The Technical Guidance of Part 9900, the proposed rule change to 10 CFR 50.55a, and enforcement action are the methods that have been used to alert licensees regarding the NRC's policy on Code interpretations that conflict with NRC guidance.

The requirements of TS 3.6.G.1.b were applicable for the flaw found in the BFN-3 RCIC system steam supply piping. The licensee's position is that the TS is not applicable for conditions (such as this flaw) found at power. Published NRC guidance leads the NRR staff to conclude that the licensee did not meet the requirements of the TS since RCIC should have been declared inoperable when the steam leak could not be isolated.

The licensee's actions did not meet the expectations promulgated in Section 6.15 of Inspection Manual Chapter 9900 regarding actions to be taken if a leak is discovered in a Class 1, 2, or 3 component. Although the repair was reasonably prompt (approximately 2 days after discovery of the source of the leakage), the licensee did not declare RCIC inoperable while pursuing repair options.

Conflicts between ASME Code interpretations and NRC requirements are addressed in the Technical Guidance of Part 9900 of the NRC Inspection Manual and in the proposed rule change to 10 CFR 50.55a. In addition, the proposed rule change also notes that in some cases Code interpretations have been issued that conflict with NRC requirements, and these cases resulted in enforcement actions.

Docket No. 50-296

