UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-259/91-24, 50-260/91-24, and 50-296/91-24

Licensee: Tennessee Valley Authority
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1101 Market Street
Chattanooga, TN 37402-2801

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

Facility Name: Browns Ferry 1, 2, and 3

Inspection Conducted: June 15 - July 15, 1991

Inspector: C. A. Patterson 8/6/91
C. A. Patterson, Senior Resident Inspector Date Signed

Accompanied by: E. Christnot, Resident Inspector
W. Bearden, Resident Inspector
K. Ivey, Resident Inspector
G. Humphrey, Resident Inspector

Approved by: Bruce A. Wilson for 8/6/91
Paul Kellogg, Section Chief Date Signed
Inspection Programs
TVA Projects Division

SUMMARY

Scope:

This routine resident inspection included sustained control room observations, power ascension test review, surveillance observation, maintenance observation, system pre-operability checklist, review of nuclear performance plan, corrective action tracking system, Unit 2 and 3 interface controls, reportable occurrences, Part 21 reports, and action on previous inspection findings.

Results:

The licensee continues to make progress toward completion of the power ascension test program, paragraph 2. Two NRC holdpoint releases were obtained during this period. The licensee is on schedule for completion of the remaining program. The plant operating crews continue to improve. On-shift communications and control of plant evolutions have been recognized as strengths.

A violation was identified by the inspector for failure to take corrective action for problems associated with Unit 2 Primary Containment Radiation Monitor three pen recorders, paragraph 2. An alarm condition was not adequately assessed because the recorder spikes occurred on a nonalarming radiation monitor. Two pens were found reversed. A field design change notice to correct the problems had been deleted. The units recorder designation and chart recorder papers were in units of MR/HR instead of R/HR. The chart paper had been corrected previously but the wrong paper was reinstalled due to an incorrect operator aid cross-reference.

A violation was identified for failure to follow procedure for equipment restoration when releasing a hold notice, paragraph 2. Adjacent .25 ampere and 15 ampere fuses were installed in the wrong locations. This resulted in the failure of the diesel generator output breaker to trip on a trip signal from the control room and motorized the diesel generator for seven minutes. The reinstallation of the fuses was required to be independently verified.

A non-cited violation was identified for inadequate Post Maintenance Test on Rosemount transmitters, paragraph 5. The visual inspection at system pressure had not been included in the work order as required by plant procedures. The work order did include a post maintenance test and the licensee promptly corrected this omission.

An unresolved item was identified for Rosemont transmitter failures, paragraph 5. The licensee had previously reported the cause of similar failures for Unit 2 in licensee event report 84-08, Revision 1, dated July 13, 1987, to be from pulse dampening devices installed in the instrument sensing lines. The devices were removed to correct the problems. No devices were installed in Unit 2 and the licensee is trying to resolve the failure mechanism.

REPORT DETAILS

1. Persons Contacted

Licensee Employees:

*O. Zeringue, Vice President, Browns Ferry Operations
*L. Myers, Plant Manager
*M. Herrell, Operations Manager
J. Rupert, Project Engineer
M. Bajestani, Technical Support Manager
R. Jones, Operations Superintendent
A. Sorrell, Maintenance Manager
G. Turner, Site Quality Assurance Manager
P. Carier, Site Licensing Manager
*P. Salas, Compliance Supervisor
*J. Corey, Site Radiological Control Manager
R. Tuttle, Site Security Manager

Other licensee employees or contractors contacted included licensed reactor operators, auxiliary operators, craftsmen, technicians, and public safety officers; and quality assurance, design, and engineering personnel.

NRC Personnel:

P. Kellogg, Section Chief
*C. Patterson, Senior Resident Inspector
E. Christnot, Resident Inspector
W. Bearden, Resident Inspector
K. Ivey, Resident Inspector
*G. Humphrey, Resident Inspector

*Attended exit interview

Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Sustained Control Room and Plant Observation (71715)

The inspectors reviewed and observed the licensee's activities in the control room on a continuing basis. The observation/reviews included control room conduct, shift turnover and relief, shift logs and records, event response, surveillance testing, and maintenance activities. The inspectors attended licensee operational and management meetings, performed plant walkdowns, and discussed observations and reviews with licensee personnel. Specific observations and reviews are noted below.

a. Unit Status

At the start of this report period the Unit 2 reactor was critical at 250 psi pressure for testing safety relief valves. At the end of the period, the plant was at 50 percent power. Significant events during the month were as follows:

June 17 NOUE due to TS required shutdown from two inoperable SRVs. (See paragraph 4).

June 25 Released from NRC holdpoint number two and mode switch shifted to RUN.

June 27 Unit tied to grid.

July 1 NOUE due to TS required shutdown from a manual scram because of high torus water temperatures (See paragraph 5).

July 3 Released from NRC holdpoint number three and authorized to exceed 25 percent power.

b. Primary Containment Radiation Monitors

On May 24, 1991, an inspector identified several problems with control room instrumentation used to monitor primary containment radiation levels. Additional information concerning this issue can be found in IR 91-21. The inspector performed followup inspection associated with this issue during this reporting period and identified the following problems:

Wiring/drawing errors resulted in the green/blue pens on control room recorder 2-RR-90-272CD, associated with 2-RM-90-272A, Division I Drywell Gamma Radiation Monitor, and 2-RM-90-272B, Division I Suppression Chamber Gamma Radiation Monitor, being reversed (leads rolled). A similar condition existed for the green/blue pens on recorder 2-RR-90-273CD associated with 2-RM-90-273A, Division II Drywell Gamma Radiation Monitor, and 2-RM-90-273B, Division II Suppression Chamber Gamma Radiation Monitor.

One of the four older low range radiation monitors, 2-RM-90-272A, had been removed from panel 9-54. Mechanical drawing 2-47E610-90-2, note 2 stated that the monitor would remain out of service for Unit 2 cycle 5 only. However TVA drawing 828E307-2, Rev 2 showed 2-RM-90-272B as the radiation monitor that was removed. Monitor 2-RM-90-272B was in service on May 24, 1991. An operations caution order, #2-90-862, also referenced the incorrect radiation monitor.

The range shown on labels located on recorders 2-RR-90-272CD and 2-RR-90-273CD was incorrectly stated as reading up to 1X10E+7 MR/HR rather than 1X10E+7 R/HR as required to satisfy the requirements of TS Table 3.2.F and NUREG 0737. The third pen (red) on each of these recorders provided a remote indication for high range drywell radiation.

Both of the above recorders contained incorrect chart paper which also stated that the units were MR/HR rather than R/HR as required. This had occurred even though the correct paper had already been identified and was available in the control room.

The inspector held discussions with members of licensee management to determine the status of the licensee's investigation into the causes of these problems. During this review the inspector determined that a series of errors had led up to these problems. Included in the licensee's investigation findings were the following causes:

The newer high range containment radiation monitors and the three pen recorders had been added under ECN P0324 during 1986. That work had been accomplished using vendor unique identifiers which did not agree with TVA unique identifiers.

During SPOC related activities which occurred in December 1990, the system engineer and instrumentation maintenance personnel identified the problem with the reversed recorder pens. However the design document (FDCN 15208A) initiated to correct the discrepancies was later canceled without the system engineer's knowledge. A drawing discrepancy had been written to correct TVA Drawing 828E307-2. This occurred because the older low range radiation monitors were not considered part of the restart boundary since no TS requirements applied.

The use of incorrect chart paper was primarily due to an incorrect operator aid used as a recorder chart paper cross reference. The operator aid referenced an error that had originally occurred during initial delivery of the equipment. The recorders were supplied in 1983 with incorrect chart paper which was not per the TVA contract specification. This error had been identified during installation and new chart paper was obtained for the recorders. No effort was made to correct either the operator aid or the labels located on the recorders. The correct paper had been placed in the recorders during the SPOC process but was replaced with the incorrect paper at a later point.

The recorders associated with the high range radiation monitors are required by NUREG 0737 and TS Table 3.2.F. Although the licensee's investigation showed that the high range radiation monitors were properly calibrated and reading the correct scale (10E+7 R/HR) at the local indication, the required range was not supported by the associated recorders located in the control room. The older drywell and suppression chamber radiation monitors are not required by TS but are included as part of the preplanned alternate methods in the event that the required high range radiation monitors fail. Additionally, these problems were identified by NRC personnel rather than licensee control room personnel. This failure constitutes a failure to promptly identify and correct conditions adverse to quality and will be VIO 260/91-24-01, Failure to Correct Containment Radiation Monitoring Problems. The annunciator response and reversed pen problem were the first examples of this VIO. The units designation was the second example of this VIO.

c. Manual Trip Due to Torus High Temperature

On June 28, 1991, the unit was disconnected from the grid and the turbine taken off line for balancing. The MSIVs were closed to repair a steam line drain leak while the reactor remained critical. The RCIC system was placed in operation at 6:30 p.m. for pressure control recirculating water from the CST to the CST with exhaust steam going to the torus. The licensee was taking torus water temperature readings every five minutes as required by TS with plans to initiate torus cooling at 90 degrees. The temperature indication remained constant at 87 degrees. At 2:35 a.m. on June 29, a RHR pump was started for a SI and a rapid rise in torus water temperature was observed. At 95 degrees EOI-2 was entered and at 110 degrees the reactor was manually tripped as required by TS. A NOUE was declared at 3:15 a.m. due to a TS required shutdown. The NOUE was terminated at 3:58 a.m. after the water temperature had decreased to 103 degrees.

The licensee conducted a thorough evaluation of the event and determined that thermal stagnation had occurred in the torus while running RCIC. Due to the location of the 16 RTDs on the inner lower side of the torus, the bulk water temperature was not adequately represented without flow or mixing in the torus. The licensee implemented a number of assessments of equipment and personnel actions to prevent reoccurrence.

(1) Corrective Actions

The licensee conducted a debrief of the operations crew that scrammed the plant and conducted a technical review of the data associated with this transient. The STA performed a preliminary scram evaluation in accordance with PMI 15.8.

The technical review concluded the 31 degree F rise in suppression pool water temperature was a realistic value based on what was seen on previous RCIC operations. The lack of change in bulk temperature indication suggested a substantial amount of stratification. The starting of the RHR system for surveillance testing mixed the water and eliminated the stratification. The

torus bulk temperature instrumentation appeared to function correctly to the postulated heat load on the torus during the transient. The temperature monitoring system responded correctly during previous events where heat was added to the torus such as the SRV/HPCI tests. Torus temperature monitoring system used RTDs equally spaced within the inside bottom wall of the torus and their outputs were averaged. The RCIC steam exhaust piping exits along the outside wall of the torus through a sparger. This physical arrangement created the potential for stratification to exist.

The licensee implemented the following corrective actions:

(a) Operations Department issued standing order OS-0036 that directed operators to initiate RHR suppression pool cooling when any activity is performed which adds heat to the torus and would result in reaching a bulk torus temperature of 95 degrees F.

(b) Training Department conducted training prior to each operations shift on the significance of the event and preventative actions

(c) TVA Obtained vendor concurrence of their assessment that the event was attributable to thermal stratification.

(d) Torus stresses due to thermal stratification were analyzed and judged acceptable.

(e) GE Service Information Letters were reviewed. No unimplemented recommendations or unusual factors to consider to prevent thermal stratification were found.

(f) No outstanding safety issues or adverse trends were identified by the STA in his preliminary scram evaluation.

(g) Operations Manager will discuss the responsibilities of maintaining an overall "big picture" during the PATP with Operations Advisor and STA at the beginning of each shift .

(h) Several OIs will be revised to include specific procedural requirements to cool the torus when operating equipment which adds significant heat load to the torus.

(i) Torus temperature instrumentation operability will be checked and correct alarm/annunciator response will be verified.

(j) Daily check program for proper operation of control room recorders will be developed.

(k) Action plan to identify and monitor other abnormal sources of heat to the torus will be developed.

(1) Explore the use of the "T-Pool" computer program with the GE to postulate the amount of thermal stratification for this event and confirm the licensee's operating experience.

The inspector concluded that since there was no omission of prior problems in this area, the licensee was following TS for monitoring temperature, and corrective action taken, no violation was warranted. This problem was similar to unexpected equipment malfunction which would not normally be cited.

(2) Upon review of the preliminary scram evaluation done by the STA in accordance with PMI 15.8, an inspector noted a discrepancy in the sequential events recorder printout. At the time the reactor trip actuators were indicated, the East and West Scram Discharge Volume High Water Levels for B through H indicated "alarm". However, the West Scram Discharge Volume High Water Level A indicated "normal". At the time the manual scram was reset, the B through H levels indicated "normal" and the A level indicated "alarm". This discrepancy was not noted or addressed in the report prepared by the STA. The report also indicated that the SOE recorder was turned off; however, the SOE recorder printout for the event was included in the package. The inspector was informed that there was a problem in the computer software that causes the words "alarm" and "normal" to print in reverse order. There were two SOE recorders and one was secured for maintenance which caused the erroneous indication. A thorough preparation and review of this evaluation should have detected and annotated the printout so it would stand alone as an accurate and complete evaluation of the event requiring no additional clarification. The licensee initiated actions to correct the computer printout.

d. Failure to Follow Procedure for Hold Notice Release

The 1D DG engine was motorized on July 9, 1991, during engine and generator post maintenance testing. The incident occurred because the generator breaker could not be tripped from the control panel in the control room due to improper fuses installed in the breaker control power trip circuit. At the time that the event occurred, the equipment was in an inoperable status.

A clearance (Hold Notice) on the 1D DG was authorized by the ASOS on July 9, 1991 to permit maintenance on the engine fuel transfer pump. Clearance No. 0-91-0501 specified seven different tags to be hung, including,

Tag No. 5	D 4KV SD BD COMP 20 D DG OUTPUT BREAKER	RACKED OUT

Tag No. 6 D 4KV SD BD COMP 20 FUSES PULL AND BAG
CONTROL POWER FUSES"

to permit the maintenance to be performed. The maintenance activity was completed and the clearance holder released the clearance. Tags were removed by Operations personnel and included "Independent Verification" of proper system configuration during system restoration.

Later, 0-SI-4.9.A.1.a (D), Diesel Generator D Monthly Operability Test, as a normally scheduled surveillance was initiated as the PMT for the maintenance activity. After the two hour load test specified by the SI, the control board operator unloaded the generator to 50 KW and 50 kVAR, and attempted to trip the generator output breaker (1816). Breaker position lights showed the breaker did not open. A Protective Relay Alarm sounded. Current, voltage, and power indications were noted abnormal. An operator was dispatched to trip the 1816 breaker locally. The breaker remained closed after the initial trip signal for seven minutes before it could be tripped locally.

The licensee determined that the cause of the breaker failure to trip from the control room was an improperly sized fuse (0.25 amp installed vs. 15 amp required) in the trip control power circuit. The fuse blew before the trip solenoid actuated. The licensee performed engine and generator tests to determine if any equipment damage was sustained, and an investigation to determine root causes of the incident and required corrective action. The generator was restored to operability on July 10, 1991.

The inspector reviewed procedures and records to determine the causes and safety significance of the incident.

SDSP-14.9, paragraph 6.6 Releasing a Clearance, required that, "For Hold Notices, an independent verifier to independently verify the removal of each tag and component positioning." The inspector noted that the Clearance Sheet (Form SDSP-216) included verification initials, indicating that some form of verification activity was performed. SDSP-3.15 (Rev. 7), Independent Verification, paragraph 6.1.3 required, "Independent verifications should ensure that each check constitutes an actual component identification and a determination of the component's required and actual position." Paragraph 6.4.3 required for circuit breakers that, "To verify a breaker is restored to service, the operator will ensure the control power is energized by inspecting the appropriate switches, indicating lights, fuses or fuse blocks, and ensure the breaker is fully racked in ...". Based upon the above requirements, the inspector concluded that if verification of control power fuse restoration (Tag No. 6) had been performed in accordance with the procedure, the improper type and size fuses in the trip and control board light circuit would have been detected.

Additionally, SDSP-14.9 (Rev.12), Equipment Clearance Procedure, required in paragraph 6.1 General Requirements, in the section of "Special Requirements for Electrical Clearances: When racking-in or racking-out 4160 volt and 480 volt breakers all the provisions of GOI-300-2 4160v, 5kv, 15kv and 480v breaker rack-in/rack-out instructions shall be followed." General Operating Instruction GOI-300-2 (Rev.4), Electrical, required in paragraph 5.2, "GE 4160V Horizontal Models, Rack-In Checklist" that the breaker be closed and tripped using control power and controls inside the auxiliary compartment above the breaker with the breaker in the test position. The licensee is reviewing if the breaker (Tag No. 5) had been restored in accordance with procedure, the improperly sized fuses restored from Tag No. 6 in the trip circuit would have been detected during breaker operation in the test position (approximately 10 amps is required to activate trip solenoid).

The licensee is conducting an incident investigation of the event and implementing several items of corrective action such as fuse labeling, procedure revision, and operator training.

The inspector concluded that a violation had occurred in that operations personnel did not follow procedure in releasing a Hold Notice. This is identified as VIO 259, 260, 296/91-24-02, Failure to Follow Clearance Procedures.

e. Radiation Monitors

The inspectors followed maintenance, operations and engineering activities associated with the radiation monitors for the RCW and other systems, and the area CAMs that support Unit 2 operations. Low flow conditions have been experienced on several off-line monitors, particularly those associated with RCW. A ready solution to the flow problems was not found, but increased attention in the form of weekly backflushing of all offline monitors and chlorination of the RCW system was instituted. Monitor 3-RM-90-132 on the RCW system experienced significant problems with low flow and was inoperable for much of the period. Acceptable flow conditions were achieved and the monitor was declared operable on July 2, but continued instances of flow degradation were anticipated by plant personnel based on past performance in hot weather conditions.

As of June 19, 10 out of 12 area CAMs were inoperable with compensatory sampling being performed. These instruments were not addressed in TS and therefore were assigned a 4A or 4C priority for corrective maintenance. The problems typically were with the source check function of the monitors, false alarms due to alarm setpoints being too low, high flow rate through the monitor, or other miscellaneous equipment problems. Work to correct the problems had not been performed due to the large amount of higher priority work items being performed as part of the power ascension program. The licensee emphasized the importance of reducing the outstanding number of monitors out of service. By July 6 the number of inoperable CAMs was reduced to 5.

Following inerting of the drywell on June 23, the licensee began to experience difficulty in maintaining the drywell oxygen content without continuously purging and adding nitrogen. On July 6, it was discovered that the 2-RM-90-256 drywell CAM was drawing air from the Unit 2 Reactor Building through a pressure regulator valve and pumping it into the drywell along with the returning sample stream. A modification was installed to eliminate the flow path from the Reactor Building atmosphere.

Two violations were identified in the Sustained Control Room and Plant Observation.

3. Plant Restart Test Program (71715)

The inspectors witnessed in-progress testing described in the Master Startup Operations/Testing Instruction, 2-SOI-100-1. These tests were designed to demonstrate that control systems and equipment would perform as designed. The major testing activities reviewed during the reporting period include, but were not limited to the following:

a. 2-TI-82, Drywell Atmosphere Cooling

The inspector reviewed and observed portions of 2-TI-82, Drywell Atmosphere Cooling System. The purpose of the test was to demonstrate the ability of the drywell atmosphere cooling system to maintain design temperature conditions in the drywell during low power conditions. The test is scheduled to be performed again at high reactor power. The test was performed during plant heatup to rated conditions with vessel pressure at 890 psig and reactor thermal power estimated to be 45 MWt.

The acceptance criterion for the test was that the bulk volumetric average drywell temperature not exceed 150 degrees Fahrenheit. The results of the test indicated that the drywell bulk volumetric average temperature was calculated to be 130.4 degrees Fahrenheit. There were two TDs generated during this test. TD-1 dealt with a deviation from the equipment alignment for the drywell cooling fans. This was due to drywell piping support inspections in progress necessitating that all fans be running instead of the normal alignment of one fan off on each bank. TD-2 documented that the OD-3 program for determination of reactor power level was inaccurate at the plant conditions that existed. These TD's are scheduled to be dispositioned by the completed reperformance of this test at high reactor power.

The inspector concluded from the review and observations that the test was performed in a controlled manner and in accordance with the

approved procedure. The results were valid. No deficiencies were identified.

b. 2-TI-183, Reactor Water Cleanup System

The inspector reviewed the completed 2-TI-183, Reactor Water Cleanup System, which was performed on June 22, 1991. The purpose of this test was to verify a flow path to the vessel is available during RCIC injection by insuring the proper operation of check valve 2-69-579. This valve is in the RWCU return line to the vessel. The RCIC return line is between check valve 2-69-579 and the vessel. This test was performed during plant heatup at 890 psig. The check valve was verified to close by acoustically monitoring the piping while momentarily securing the RWCU pumps. No test deficiencies were identified.

c. 0-TI-135, Process Computer and Core Performance

The inspectors observed portions of 0-TI-135, Process Computer and Core Performance. Some problems were experienced during the performance of 0-TI-135 due to the failure of the process computer and inaccuracies in the data taken for the manual heat balance calculation, which were finally resolved satisfactorily. The RWM function of the process computer was inoperable during the performance of the tests, and compensatory measures were taken for control rod movements in support of power ascension and testing.

d. 2-TI-253, Rod Block Monitoring System

Performance of 2-TI-253 was attempted at a power level of approximately 20 percent. The test verified the operability of the RBM system. Satisfactory completion of the test was not obtained due to 16 LPRMs not being onscale due to too low a power level and another 19 LPRMs being bypassed in the APRM channels due to spiking, high readings, fluctuations or other problems. The test was rescheduled for completion at the 50-55 percent power plateau. The licensee performed corrective maintenance activities on the bypassed LPRMs, consisting of capacitive discharge of the detectors to eliminate uranium "whiskers" which were shorting out the detectors. This evolution succeeded in reducing the number of bypassed LPRMs from 19 to 7 in the 6 APRM channels.

e. 2-TI-20, Control Rod Drive System Testing

The control rod scram time testing was performed at less than 40 percent power in accordance with TS requirements. The reactor pressure was increased to 950 psi for the testing evolution as required by 2-SOI-100-1. Prior to the start of the test an NRC inspector noted that the procedure for the scram time testing, 2-SI-4.3.C, directed an AUO to initiate the rod scram from the remote test panel in the Unit 2 auxiliary instrument room. This was planned evolution contrary to 10CFR50.54(i) requirements that a licensed operator perform reactivity manipulations. The licensee concurred with the NRC observation and placed a hot licensed operator at the panel to perform all control rod scrams. The test was completed with all scram times meeting TS requirements, but the scram time for rod 38-55 was significantly slower than the next slowest rod (5.07 seconds vs. 3.51 seconds). A WR was initiated to investigate the cause of the slow scram time.

f. 2-TI-149, Reactor Water Level Measurements

An inspector reviewed completed portions of 2-TI-149, Reactor Water Level Measurements. The purpose and scope of this test were to collect reactor water level data at various reactor power levels to verify that monitoring instrumentation operates correctly. By the end of this reporting period, the licensee had completed the test up to the 55 percent reactor power plateau. Data was collected at various combinations of reactor power, reactor pressure, and core flow. Five TDs were written against the test. Four of the TDs were dispositioned as procedural inconsistencies or non-stable plant conditions. One Level 2 TD remained open concerning problems obtaining temperature data on the condensing chambers because of the failure of test equipment due to high drywell ambient temperatures. This TD was being reviewed further by DNE. The results of this first plateau of testing indicated that water level instrumentation responded as expected and all criteria were met to support continued operation. Further data will be taken as reactor power is increased up to 100 percent. No concerns were identified by the shift inspectors.

g. 2-TI-222, Testing, Maintenance and Calibration Checks of PASS and PASS Components

The BFNP post accident sample system was installed during the extended outage. The FSAR has not been updated to reflect this installation. SOI-100-1 did not include PASS testing. However, TI-222 was factored into the PATP schedule and accomplished on July 2, 1991.

The inspector reviewed the completed test document. The test required that the ratio of a PASS sample analysis to the results from a normal sample drawn at approximately the same time fall between 0.5 and 2.0. The test offered the options of liquid samples analyzed for I-131 and Cs-137 or containment (drywell or suppression pool) atmosphere samples analyzed for Kr-85 and Xe-133. The procedure recommended a performance schedule of quarterly testing which covered all sample options during a one year cycle.

Both options were performed, but only the I-131 liquid sample contained enough of the isotope of interest to provide valid results.

The I-131 results were satisfactory, and the licensee intends to perform the test again at higher reactor power levels to satisfactorily complete the test.

4. Surveillance Observation (61726)

The inspectors observed the performance of required SIs. The inspections included reviews of the SIs for technical adequacy and conformance to TS, verification of test instrument calibration, observations of the conduct of testing, confirmation of proper removal from service and return to service of systems, and reviews of test data. The inspectors also verified that LCOs were met, testing was accomplished by qualified personnel, and the SIs were completed within the required frequency. The following SIs were reviewed during this reporting period:

a. 2-SI-2.1, Core Performance Data

b. 2-SI-4.1.a.11 (II), MSIV Closure - RPS Trip Functional Test (Channel B1/B2)

c. 2-SI-4.1.B-2, APRM Output Signal Adjustment

d. 2-SI-4.1.B-3, RPS LPRM Calibration

e. 2-SI-4.2.C-3.2 FT, Instrumentation that Initiates Rod Blocks/Scrams IRM FT with Mode Switch in REFUEL or STARTUP

f. 2-SI-4.3.c, Scram Insertion Times

g. 2-SI-4.5.E.1.c, HPCI System Motor Operated Valve Operability

h. 2-SI-4.5.E.1.e, HPCI Flow Rate Test at Normal RPV Pressure

i. 2-SI-4.5.E.1.d, HPCI Flow Rate Test at Normal RPV Pressure

j. 2-SI-4.6.D.2, Main Steam Relief Valves Manual Cycle Test

During the performance of the 2-SI-4.6.D.2 for MSRV 2-PCV-1-34, no acoustic monitor indication was received; instead the acoustic monitor for MSRV 2-PCV-1-42 indicated as expected for MSRV 2-PCV-1-34. The SOS stopped the test and declared MSRV 2-PCV-1-34 inoperable because of inadequate indication. Upon further discussion with Operations personnel and advisors, the SOS declared MSRV 2-PCV-1-42 inoperable also. TS 3.6.D.1 states that when more than one relief valve is known to be failed, an orderly shutdown shall be initiated and the reactor depressurized to less than 105 PSIG within 24 hours. Since the SOS considered MSRVs 2-PCV-1-34 and 2-PCV-1-42 to be failed, an orderly shutdown was begun. In addition, EPIP-1, Emergency Plan Classification Logic, requires that a NOUE be declared when a TS LCO is reached requiring shutdown. The licensee declared a NOUE at 12:28 p.m. (CDT) on June 16, 1991.

The licensee conducted testing on the acoustic monitors for the two failed MSRVs and determined that the cables to the accelerometers were reversed resulting in reverse indications. Based on this finding, the licensee declared the acoustic monitors for these MSRVs inoperable and declared the MSRVs operable. The licensee exited the NOUE at 4:45 p.m. (CDT) on June 16, 1991.

The licensee conducted an incident investigation which determined that the acoustic monitors for 2-PCV-1-34 and 2-PCV-1-42 were cross wired during the performance of modification P0284. The investigation also identified that the PMT conducted for the modification did not detect the cross wiring error. The licensee rewired the acoustic monitors and completed the performance of the SI on June 20, 1991. All MSRVs tested met acceptance criteria. No other deficiencies were identified.

The licensee also experienced bar graph "latch up" problems with three of the acoustic monitors during the performance of this test discussed in this IR.

The inspector is continuing to review this item. Some problems were found with the accoustic monitor sealing in the drywell during a closeout inspection. These problems may have been introduced during the correction of the sealing problems and were not addressed in the investigation report.

No violations or deviations were identified in the Surveillance Observation area.

5. Maintenance Observation (62703)

Plant maintenance activities were observed and/or reviewed for selected safety-related systems and components to ascertain that they were conducted in accordance with requirements. The following items were considered during these reviews: LCOs maintained, use of approved procedures, functional testing and/or calibrations were performed prior to returning components or systems to service, QC records maintained, activities accomplished by qualified personnel, use of properly certified parts and materials, proper use of clearance procedures, and implementation of radiological controls as required.

Work documentation (MR, WR, and WO) were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which might affect plant safety. The inspectors observed the following maintenance activities during this reporting period:

a. WO# 91-27492-00, Troubleshoot and Repair U2 RWL Master Level Controller 2-LIC-046-0005.

b. WO# 91-34461-00, Troubleshoot CRD 38-51 Red Backlight Not Lit.

c. Disassembly and Repair of Valve 2-FCV-64-34

d. WO# 91-35826-01, Replace Rosemount Transmitter 2-FT-1-13.

Rosemount Transmitter Failures

The licensee reported in LER 84-08, Revision 1, dated July 13, 1987, the cause of numerous transmitter failures during 1984 on Unit 1. Following extensive testing of the transmitters (Rosemount Model 1153DD7) by both TVA and the manufacturer, it was concluded that the offscale conditions could be attributed to the behavior of the pulse dampening devices (snubbers) installed in the instrument sensing lines. The snubbers were removed and Unit 1 operated for seven months with no further problems.

Starting on July 7, 1991, a total of seven failures have occurred on Unit 2. All were again Model 1153DD7. The licensee identified that 18 transmitters were 1153DD7. Unit 2 does not have snubbers installed. There are 16 transmitters for the main steam line high flow and two for HPCI steam line flow. All 18 were replaced by July 12, 1991, with refurbished transmitters. The licensee initiated a CAQR to track resolution of the problem. Other planned actions are to have Rosemount do a root cause analysis of failures and have an independent laboratory do an analysis.

Resolution of the cause of the failures and the SI test method discussed below will be a URI, 259, 260, 296/91-24-03, Rosemount Transmitter Failures.

(1) Inadequate PMT for Rosemount DP transmitter replacement

Work Order 91-24439-01 replaced MSL C flow element differential pressure transmitter BFN-2-PDT-001-0036B (defective Rosemount transmitter). The PMT was logged as complete in the ASOS log as complete at 1139, July 9, 1991. The inspector reviewed the WO, and noted that the required PMT was the successful performance of 2-SI-4.2.A-7(B), Primary Containment Isolation Signal MSL High Flow Instrument Channel B1 Calibration. The inspector reviewed the applicable section of the SI, and noted that the pressure applied to the transmitter was 150 psid, notwithstanding the normal operating pressure being approximately 1,000 psi.

The inspector noted that SDSP-6.7, Post Maintenance Test Program, required in Attachment B that the replacement of a component in an instrument loop required, "Inspect mechanical joints under normal operating or hydrostatic test pressure to verify no leakage." This inspection, at this pressure, was not included and documented as performed in the WO. Similar conditions were noted in other WOs prepared for replacement of other MSL High Flow transmitters. The inspector concluded that

the PMT requirements on the WO were inconsistent with the requirements of SDSP-6.7, and thus constituted a violation of procedure. The licensee promptly corrected this problem. This is identified as NCV 260/91-24-04, Inadequate PMT on Rosemount Transmitter. This NRC identified violation is not being cited because criteria specified in Section V.A of the NRC Enforcement Policy were satisfied.

(2) Inconsistency between Technical Manual Test Requirements and Surveillance Requirements for Rosemount Transmitters

The inspector reviewed surveillance requirements performed on high steam flow Rosemount differential pressure transmitters after the failure of several transmitters to determine if technical manual requirements were properly implemented. Procedure 2-SI-4.2.A-7(C), Rev. 5, Primary Containment Isolation System Main Steam Line High Flow Instruments Channel A2 Calibration, checked the calibration of the instruments in Channel A2 at 18 month intervals. The transmitters send milliampere signals, proportional to transmitter pressure inputs of 0 to 150 psid, to their associated analog trip units; the transmitters' normal operating pressure is approximately 1000 psig.

Instruction Manual BFN-VTD-R369-0120, Rosemount Alphaline, Model 1153 Series D Pressure Transmitters, Section III, Calibration, described manufacturer calibration requirements. "Correction for High Pressures, Zero", described the procedures to be implemented to, "...eliminate the zero effect associated with high line pressures specified..." elsewhere in the instruction manual. The procedure required the transmitter process connections to be equalized at normal operating pressure, and the "zero" adjustment manipulated until the ideal output at zero differential pressure input is observed. Expected values of error introduced by operation of the transmitter at "high line pressures" were listed in the technical manual.

The inspector reviewed the SI, and noted that the zero adjustment at normal operating pressure was absent from the instruction. Plant staff indicated that the technical manual provision for the zero check was not included in the SI since the effect on the transmitter should be small.

Unit 2 TS Table 4.2.A, Surveillance Requirements for Primary Containment and Reactor Building Isolation Instrumentation, listed the surveillance requirements for the main steam line high flow instruments in question. Note 28 for Table 4.2.A required, "Calibration consists of the adjustment of the primary sensor ... so that they correspond within acceptable range and accuracy to known values of the parameter which the channel

monitors ...". Based upon a comparison of the SI and the technical manual requirements for instrument accuracy checks, the inspector concluded that "calibration" as defined by the TS was not being performed during performance of the SI since adjustment (or checking for need of adjustment) was not performed at normal operating pressure. This SI inadequacy is part of the URI concerning Rosemount Transmitter failures.

One NCV was identified in the Maintenance Observation area.

6. System Pre-Operability Checklist (71707)

The inspectors continued to monitor the licensee's activities to upgrade plant systems and documentation which includes drawings, procedures, system descriptions etc., prior to their return to service. The following are a listing of those systems reviewed during the reporting period.

a. Lube Oil System (System 20)

The SPOC for this system was completed on May 6, 1991. The system had been previously walked down with the licensee. No major items were identified that would prevent the system from operating properly. In addition, the completed package was reviewed and it was determined that no adverse conditions existed that would impact operability.

b. Main Turbine (System 47)

This SPOC package was completed on May 23, 1991. Only one deferral remains open and cannot be dispositioned until certain power levels have been achieved. Some deficiencies were identified but were evaluated to not impact operability of the equipment. Based on this review, the system was found to be acceptable for plant restart.

7. Review of the Browns Ferry Nuclear Performance Plan Corrective Action Tracking System

An inspector conducted a series of inspections from November 1990 through the present, to examine the system used to track the NPP items to closure. A review of the process was made; and items were selected for verification of their completion.

The inspector reviewed SDSP 7.3, Operational Readiness Program for Browns Ferry Unit 2, used to implement the NPP Volume 3 requirements, and SDSP 15.6, Commitment Management Tracking, which define the commitment tracking system implementation at BFNP. Interviews were conducted with licensee personnel responsible for program tracking and with individuals implementing specific items in the NPP. In addition to the program review, the inspector selected ten commitment packages for review. Field implementation of the commitments was verified and compared to the status indicated in the packages.

The tracking system was found to have accurately tracked each item to completion. After an item was complete the package was closed and not examined again by the tracking system. The inspector noted that in some cases the final fix for the problem indicated in the NPP had evolved beyond the commitment made years ago in the NPP. An example of this was the EA group, whose functions are now part of the corporate quality organization.

The BFNP quality organization conducted an audit of package closure for NPP items, and in some cases reopened closed packages to update them for changes made since the item's original closure date. In addition, audits were also conducted by the SMART team. These audits ensured that all items shown as closed were in fact closed.

The commitment tracking program was shown to be effective in tracking commitments. The audits performed ensured accuracy of the system closures prior to Unit 2 restart. Periodic reviews of the tracking system will continue to be performed by the NRC to insure commitments for post restart of Unit 2 are met.

8. Unit 2 and Unit 3 Interface Controls

An open item in the ORAT was 260/91-201-01, Determination of Responsibility for Communication Between Unit 2 and Unit 3. This item was closed in IR 91-202. The licensee issued a memorandum dated April 18, 1991, that initiated the development of a formalized administrative program to delineate responsibilities and lines of communication between BFN Operations (Unit 2) and Restart Organization (Unit 3). The memorandum recognized the need for additional procedures in the two areas.

First SSP-1.51, Unit 1 and 3 Restart Administration and Control, was issued on May 29, 1991, to clarify the role of the restart organization as part of the site organization. This procedure defines the organization principle duties, responsibilities and authorities, and its interface with the BFNP organization. The position of Restart Licensing, Restart Operation, and Restart Project Procedures are matrixed to the Restart Vice President. They receive technical direction from the respective BFNP Site Managers and are responsible to the Restart Vice President for budget, performance, and schedule.

Restart Engineering receives technical requirements and criteria from BFNP engineering and is responsible for the implementation of the requirements and criteria. They are responsible to the Restart VP for budget, performance, and schedule. Restart Quality reports directly to and receives technical direction from Site Quality. They only communicate with the Restart VP on quality related matters. The position of Restart Manager, Field Services, and Contractors report directly to the Restart VP and are responsible to him for budget, performance, and schedule. An interface chart is provided in Appendix A of SSP-1.51.

Second, a dedicated series of procedures would be issued to address specific activities identified in the Restart Project Procedure Manual. The licensee revised SSP-2.1, Site Procedures Program, to add restart project procedures as a procedure type and clarify that all site approved contractor procedures are submitted to DCRM. This change specified that procedures that contractors use which involve quality related work shall be reviewed, approved, and revised like other site procedures.

The inspector concluded that the action taken by the licensee to address open item 260/91-201-01 are being implemented. The programmatic controls are in place for the Unit 2 and Unit 3 Interface.

9. Reportable Occurrences (92700)

The LERs listed below were reviewed to determine if the information provided met NRC requirements. The determinations included the verification of compliance with TS and regulatory requirements, and addressed the adequacy of the event description, the corrective actions taken, the existence of potential generic problems, compliance with reporting requirements, and the relative safety significance of each event. Additional in-plant reviews and discussions with plant personnel, as appropriate, were conducted.

a. (Closed) LER 259/91-02, Operation Outside of Technical Specifications.

On February 1, 1991, during the performance of surveillance testing, a RLA discovered that the filter holder for CAM 1-RM-90-250, Reactor Building Ventilation Exhaust Monitor, did not contain a particulate filter or charcoal cartridge. This resulted in the failure to take a required sample and TS monitoring requirements were not met.

The inspector reviewed the LER, dated March 1, 1991, and determined that it met the reporting requirements of 10 CFR 50.73. This issue and an associated licensee investigation were reviewed in IR 91-02 and NCV 91-02-01 was issued for a violation of TS requirements. The root cause of this event was attributed to personnel error and the inspectors concluded that the licensee took appropriate corrective actions to preclude recurrence. No concerns were identified during this review of the LER.

b. (CLOSED) LER 260/91-03, Unplanned ESF Actuation of the D3 RHRSW Pump.

On February 23, 1991, the D3 RHRSW pump auto-started following the racking in of the 2B CS pump feeder breaker. After extensive investigation, the licensee found no failed components and could not determine the root cause of the unplanned start. Since the RHRSW pumps are designed to auto-start on signals from safety related systems, including CS, a spurious actuation of the associated auto-start relays was suspected as the cause.

An inspector reviewed the LER, dated March 25, 1991, and determined that it met the reporting requirements of 10 CFR 50.73. No deficiencies or concerns were identified.

10. Part 21 Reports

During the performance of 2-SI-4.6.D.2, Main Steam Relief Valves Manual Cycle Test, on June 16, 1991, abnormal MSRV acoustic monitor indications were observed. When three of the valves were opened for testing, a full flow signal (Bar Graph LED) was indicated as expected; however, when the valves were closed, the full flow indication remained. This phenomenon is known as Bar Graph "Latch-Up" and was the subject of LER 259/85-16 and a later vendor Part 21 Report. The acoustic monitor vendor issued 260/P21-85-02 on July 19, 1985, to notify licensees of a potential defect with the analog level detector within acoustic monitor modules. The Part 21 indicated that the failure was a birth defect (a failure present at manufacture or after a run time of 24 hours or less) and suggested that a special test be performed on each module. The licensee conducted the special test, in 1985, for each acoustic monitor in all three BFN units (39 total). Four of the acoustic monitors indicated a "latch-up" problem and were replaced. No later failures were identified until this reporting period.

Following identification of the "latch-up" problem during this reporting period, the licensee replaced the three acoustic monitor indicators with upgraded models which are not subject to "latch-up." In addition, the licensee replaced the indicators for two other MSRVs which had not been tested at the time the SI was stopped. The licensee performed a PMT on each of the new indicators and no deficiencies were identified. The licensee notified industry information networks to provide other licensee's with this new failure information.

The Part 21 report has not been updated and the inspector continues to review this for updating of the Part 21 report.

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

a. (CLOSED) URI 260/86-28-02, Scram Valve Timing for ATWS Modifications

On July 7, 1986, during a Unit 1 test of scram air header blowdown time to determine design input for the ATWS design modification, the licensee found the opening times for several scram outlet valves and scram inlet valves were significantly longer than expected for the test conditions. The data was believed to indicate the presence of some restriction in the scram air header or a problem in the scram solenoid pilot valves, possibly related to pilot valve discrepancies reported by GE in SIL 441. The evaluation was extended by the licensee to address possible concerns for Units 2 and 3.

The licensee rebuilt the Unit 1 scram pilot valves and noted an improvement in scram valve opening time from 20-38 seconds to less

than 20 seconds. Although this time was still longer than the expected 4-7 seconds in the original test, the licensee reviewed the scram system and found that use of the backup scram valves would result in a longer time for pressure decay off the scram valves, since the pressure bleeds off through the scram pilot valve orifices instead of through the normal scram vent path. Thus, scram valve opening times of approximately 15 seconds following the initiation of an ATWS ARI signal was consistent with the system design.

Subsequent review by NRC of the licensee's initial corrective actions as documented in IR 88-16 identified the following additional concerns:

(1) Acceptance criteria for scram pilot valve timing upon scram air header blowdown should be addressed.

(2) Perform either single rod scram testing prior to plant startup, or scram valve time tests prior to plant startup for each scram solenoid pilot valve that was refurbished in accordance with GE recommendations in SIL 441.

(3) Check the adjustment of all scram valve opening air pressures and ensure compliance with the recommended spring tension settings of GE SIL 373.

Item 3 was completed by the licensee and reviewed by NRC and found acceptable in IR 88-32 for Unit 2. Item 1 was completed by the licensee in July 1990 by performing post-modification testing on the ATWS modification through PMT-184. The test results were reviewed by the NRC in IR 90-33 and it was found that the ARI system function times were acceptable for Unit 2.

Control rod scram time testing was completed for all control rods prior to fuel load. The inspector reviewed results of 2-SI-4.3.C, Scram Insertion Times which was performed on 182 of the 185 CRDs on October 28-30, 1990, prior to fuel loading. The three remaining CRDs, which were out of service for maintenance during the first test, were subsequently tested on February 19-20, 1991 under the same conditions as the other CRDs. The testing was recommended by the reactor vendor and was performed as a functional test only of the CRDs, since the testing to show compliance with TS required reactor pressures greater than 800 psig. Scram timing was calculated, and no anomalous behavior was observed.

Additional scram timing testing will be performed following power ascension to reactor pressure greater than 800 psig as required by TS 4.3.C. The results of the testing summarized above are acceptable for closure of Item 2) above.

b. (CLOSED) URI 259, 260, 296/91-21-01, Radiation Monitor Recorder Problems.

While observing control room activities an inspector identified several problems associated with control room primary containment radiation monitoring instrumentation. Based on subsequent review of details associated with the issue, the inspector determined that a violation of 10 CFR 50, Appendix B, Criterion XVI requirements had occurred. Additional information associated with the violation is contained in this report.

12. Exit Interview (30703)

The inspection scope and findings were summarized on July 15, 1991 with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
260/91-24-01	VIO, Failure to Correct Containment Radiation Monitoring Problems, paragraph 2.
259, 260, 296/91-24-02	VIO, Failure to Follow Clearance Procedures, paragraph 2.
259, 260, 296/91-24-03	URI, Rosemount Transmitter Failures, paragraph 5.
260/91-24-04	NCV, Inadequate PMT on Rosemount Transmitters, paragraph 5.

Licensee management was informed that 2 LERs and 2 URIs were closed.

13. Acronyms and Initialisms

APRM	Average Power Range Monitor
ARI	Alternate Rod Injection
ASOS	Assistant Shift Operations Supervisor
ATWS	Anticipated Transient Without Scram
AUO	Auxiliary Unit Operator
BFNP	Browns Ferry Nuclear Plant
CAM	Continuous Air Monitor
CAQR	Condition Adverse to Quality Report
CDT	Central Daylight Time
CFR	Code of Federal Regulations
CRD	Control Rod Drive

CS	Core Spray
CST	Condensate Storage Tank
DCRM	Document Control and Records Management
DG	Diesel Generator
DNE	Division of Nuclear Engineering
EA	Engineering Assurance
ECN	Engineering Change Notice
EOI	Emergency Operating Instruction
ESF	Engineered Safety Feature
FCV	Flow Control Valve
FDCN	Field Design Change Notice
FSAR	Final Safety Analysis Report
GE	General Electric
GOI	General Operating Instruction
HPCI	High Pressure Coolant Injection
IFI	Inspector Followup Item
IR	Inspection Report
IRM	Intermediate Range Monitor
KW	Kilowatt
LCO	Limiting Condition for Operation
LED	Light Emitting Diode
LER	Licensee Event Report
LLRT	Local Leak Rate Testing
LPRM	Local Power Range Monitor
MR	Maintenance Request
MSIV	Main Steam Isolation Valve
MSL	Main Steam Line
MSRV	Main Steam Relief Valve
NCV	Non-Cited Violation
NOUE	Notification Of an Unusual Event
NPP	Nuclear Performance Plan
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OI	Operating Instruction
ORAT	Operational Readiness Assessment Team
PASS	Post Accident Sampling System
PATP	Power Ascension Test Program
PMI	Plant Manager Instruction
PMT	Post Maintenance Test
PSIG	Pounds Per Square Inch Gauge
QA	Quality Assurance
QC	Quality Control
RBM	Rod Block Monitor
RCIC	Reactor Core Isolation Cooling
RCW	Raw Cooling Water
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RLA	Radiochemical Laboratory Analyst
RM	Radiation Monitor
RPS	Reactor Protection System

RPV	Reactor Pressure Vessel
RTO	Resistance Temperature Detectors
RWCU	Reactor Water Cleanup
RWP	Radiological Work Permit
SBGT	Standby Gas Treatment System
SDSP	Site Director Standard Practice
SI	Surveillance Instruction
SIL	Service Information Letter
SOE	Sequence of Events
SOI	Special Operating Instruction
SPOC	System Pre-Operability Checklist
SRM	Source Range Monitor
SRV	Safety Relief Valve
SSP	Site Standard Practice
STA	Shift Technical Advisor
TD	Test Deficiency
TI	Technical Instruction
TS	Technical Specification
URI	Unresolved Item
VIO	Violation
VP	Vice President
WO	Work Order
WR	Work Request