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

Report Nos.: 50-259/91-26, 50-260/91-26, and 50-296/91-26

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 Units 1, 2, and 3

Inspection at Browns Ferry Site near Decatur, Alabama

Inspection Conducted: July 16 - August 16, 1991

Inspector: _____ 9/11/91
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: _____ 9/11/91
Paul Kellogg, Chief, Inspection Programs, TVA Projects Division — Date Signed

SUMMARY

Scope:

This routine resident inspection included sustained control room observations, power ascension test program, test program review, operational safety verification, procurement, reportable occurrences, and actions on previous inspection findings.

Results:

The licensee successfully completed the power ascension test program for Unit 2 on August 6, 1991, and returned the unit to normal full power operation,

paragraph two. Completion of this program without an automatic trip and continuous operation of the Unit for 34 days was a significant strength.

Two violations occurred this period. Both violations involved Unit 3 activities and control of contractor personnel.

One violation identified by a NRC inspector was for removing fire wrap from operable equipment without posting a fire watch paragraph 5. Fire wrap was removed from Residual Heat Removal Service Water pump power cables in the intake structure. The work was performed to support Unit 3 walkdowns although it was determined that the inspections had previously been performed on Unit 2. Contractor personnel preparing the walkdown inspections did not use Unit 2/Unit 3 separation drawings to plan the work. The licensee stopped all Unit 3 walkdowns until corrective actions could be implemented. At the end of this report period the corrective action plan was not complete and Unit 3 work had not resumed.

The second violation was for two fuel movement errors performed during a two week period during Unit 3 fuel sipping and inspections, paragraph 5. After corrective actions including independent verification were implemented for the first error, a second error occurred. Although overseen by a licensed operator, contractor personnel on the bridge crane performed the actual fuel movements.

One non-cited violation was identified for failure to distribute an urgent intent change to a surveillance instruction in the control room, paragraph 2. The control room operator identified this error. The licensee took prompt corrective action to remedy this document control distribution problem.

REPORT DETAILS

1. Persons Contacted

Licensee Employees:

*O. Zeringue, Vice President, Browns Ferry Operations
*H. McCluskey, Vice President, Browns Ferry Restart
L. Myers, Plant Manager
*J. Swindell, Restart 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
*J. McCarthy, Unit 3 Licensing
*P. Salas, Compliance Supervisor
*J. Corey, Site Radiological Control 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
R. Bernhard, Project Engineer

*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. Plant Status

The unit was at 50% power during the start of this report period. The major items that occurred this period were as follows:

July 17	Released from final NRC hold point. Authorized to exceed 55% power at 1:00 p.m.
July 28	Fire wrap found removed at intake structure
August 2	Reactor was shutdown as part of a planned reactor trip. Prior to this the unit operated for 34 consecutive days
August 6	The power ascension test program was completed. Continuous control room observation by NRC ended.

Successful completion of the power ascension was noted as a significant strength. The foresight of senior TVA management to supplement the plant staff with experienced GE test engineers, improve secondary plant material condition, and implement lessons learned from other utility test programs was noteworthy. Technical support strengths were test organization and test briefings. The expertise of the plant operating crews was noted by many NRC personnel during sustained control room operations. The accurate scheduling and lack of significant problems during the test program were strengths.

b. Document Control

On July 13, during the control room briefing for the conduct of the 2-SI-4.1.A-11(II), MSIV Closure - RPS Trip Functional Test (Channel B1/B2), the UO noticed that the control room copy he was going to use during the conduct of the SI did not have the latest UIC entered. UIC-07 had been approved on July 3 and should have been entered in this "Controlled" copy of the SIs by July 5 in accordance with SDSP 2.12, Paragraph 3.6.6. The control room copy of the SI was corrected at that time and the SI was correctly performed. An inspector researched the cause of this error and determined the following:

(1) The preparer of the change delivered UIC-07 to the TIC in the POB at about 5:30 a.m. on July 3.

(2) The POB TIC clerk carried out most of the actions specified in Appendix H, "Holiday, Weekend, or Third Shift Distribution," of instruction DCRM-I-306.1. However, the POB TIC clerk did not file UIC-07 in the control room binder as specified in step 8 of Appendix H. Since it was near the end of the shift, the clerk gave the copy of the UIC-07 to a day shift POB TIC clerk to be entered in the control room binders. The day shift POB TIC

clerks either forgot or misplaced the control room copy of the UIC and did not enter it in the control room binder.

(3) Subsequent standard distribution procedures also assumed that the action in step 8 of Appendix H had been carried out, so UIC-07 was never entered in the control room binder.

The licensee instituted a revised receipt log to be used to insure that UICs get entered in the control room copies as soon as they are processed in the TIC.

The inspector concluded that a violation of 10 CFR 50 Appendix B Criterion VI, Document Control, had occurred. This requires that measures shall be established that documents, including changes, are distributed to and used at the location where the prescribed activityis performed. This item was identified and corrected by the licensee. The violation is not being cited because the criteria specified in Section V.G of the Enforcement Policy were satisfied. This is identified as NCV 260/91-26-01, Failure to Update Control Room Procedure.

3. Power Ascension Test Program (72300, 72302, 72508, 72509, 72514, 72516)

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-130, Main Steam Pressure Control

The inspectors observed the performance of Section 7.3 of this TI on July 28, 1991. This phase of the test was conducted at high power to demonstrate smooth pressure control and stability of the steam loop during step changes of the pressure setpoint and to demonstrate the takeover capability of the backup pressure regulator upon failure of the controlling pressure regulator. The power level during the test was approximately 91% full power, which provided a margin to the APRM fixed scram setpoint of approximately 22%. The testing extended over two operating shifts, and thorough briefings of Operations and test personnel by the test director were observed by the inspectors. The test results met the acceptance criteria, and no adjustments were required to the pressure regulators or other process controllers. No deficiencies in the conduct of the testing were identified.

b. TI-131, Feedwater Level Control System Testing

The inspector observed and reviewed the results of Phase 3 of this TI. The purpose of the test was to verify and adjust as necessary, the stability of the feedwater control system. This consisted of placing the feedwater control system in single element and in three

element control method. The feedwater showed instability in that the desired level and the actual level would diverge. This in turn caused instability and resulted in several transients on the system. The operators and the test personnel were eventually able to get the desired and actual level to converge thereby creating stability in the system. The final physical testing was completed on July 28, 1991 with the reactor at approximately 100% power. One TD was identified involving information going to the computer. The inspector concluded from the observations and review that the test was conducted in accordance with an approved test procedure, activities were performed in a step by step controlled manner, and the test personnel performed the required adjustment as needed. No deficiencies were identified.

c. 2-TI-132, Recirculation Flow Control

The inspectors observed the performance of Section 7.5 of this TI on July 29, 1991, for the conditions of high power with all reactor feedwater pumps operating. This phase of the test was to demonstrate proper performance of the reactor recirculation flow control system following the insertion of a large and rapid negative ramp on the Master Manual Flow Controller to ensure that recirculation pump speed reduction and reactor recirculation flow reduction would respond as anticipated. This was accomplished by the operator reducing the controller setpoint to approximately 55% in one continuous manual step, which corresponded to a recirculation MG set speed of approximately 65%. The plant power level at the beginning of the test was approximately 93%, and decreased to approximately 78% following the flow reduction. Thorough briefing of Operations and test personnel by the test director were observed by the inspectors. The test results met the acceptance criteria, and no adjustments to plant process controllers were required. No deficiencies in the conduct of the testing were identified.

d. 2-TI-149 Reactor Water Level Measurements

This test collected data to verify that reactor vessel water level instrumentation was operating correctly between 0 and 960 psig. The test included collection of temperature data on the reference leg condensing chambers and on the reference leg three inches below the condensing chamber. The test results contained two TDs.

(1) Two of the temperatures measured from the top of one condensing chamber were below the specified 350 to 425 degree F range of the procedure.

(2) One of the temperatures measured on the reference leg three inches below the condensing chamber was more than 20 degrees F above drywell temperature, the permissible range specified in the procedure (reference leg was 226 degrees F, drywell approximately 135 degrees F).

The licensee attributed the TDs to the fact that the hand-held pyrometer failed during the test due to the high ambient temperature conditions that existed during the test. Since the reactor water level system has performed satisfactorily (good level agreement between all instruments) during the PATP, the licensee continued with the PATP. The inspectors concluded that the TDs did not adversely affect continuation with the PATP, based on the system response and routine observations of the systems' performance. No deficiencies were identified

e. 2-TI-188, RCIC Injection

The inspectors observed the performance of Section 7.3 of this TI on July 30, 1991. The testing was performed at approximately 91% full power. The purpose of the test was to perform a cold start of the RCIC system and inject water from the CST to the reactor vessel following the injection of a simulated low water level signal to the ECCS logic. The system flow controller response and stability was evaluated to determine if tuning of the controllers was required. Thorough briefing of Operations and test personnel by the test director was observed. The system responded as anticipated with minor adjustment of the flow controller required. No testing deficiencies were observed by the inspectors.

f. 2-TI-189, HPCI Injection

The inspectors observed the performance of Section 7.3 of 2-TI-189 on July 31, 1991. The testing was performed at approximately 75% power. The control rods were adjusted to an approximately 75% rod line in order to avoid potential instability problems in case a recirculation system runback occurred. The purpose of the test was to perform a cold quick start of the HPCI system by simulating a low water level (-45") signal and demonstrating that injection of 5000 gpm flow to the vessel was achieved within 30 seconds. Final tuning of HPCI control systems was also to be performed if required.

Following initiation of HPCI for the test, a momentary low suction pressure condition resulted in a trip of the turbine; the HPCI auto-restarted when the low suction pressure condition cleared. The test was aborted several minutes later in accordance with the test abort requirements when it was determined that the Level I test criteria of less than 30 second starting time was not achieved. HPCI was tripped and declared inoperable, and a four hour ENS report was made. During the pump start transient, the upper head gasket on the gland seal steam condenser ruptured and required replacement following shutdown.

The licensee reviewed the results of the test and developed and installed a temporary alteration consisting of a time delay of approximately 5 seconds in the suction pressure trip circuitry to prevent HPCI trip during transient starting conditions. The test

procedure was revised to incorporate additional requirements from 2-SI-4.5.E.1.d such that a rerun of the test would also satisfy TS requirements for demonstrating operability.

A repetition of the test was performed successfully on August 1, 1991. Minor adjustments were required during the test on the gain and drift settings on the control board flow controller. The torus temperature exceeded 95 degrees F, which required entry into EOI-2. The maximum temperature reached was 98 degrees F, and was monitored closely by the ASOS in command of the evolution and the SOS. During the test run a leak developed on the lower head gasket for the gland seal steam condenser. It was noted by the inspectors that the low suction pressure setpoint was not reached during this test run.

The inspectors attended both test briefings and observed that the briefings were thorough and that anticipated problems were discussed and compensatory actions planned. The command and control function by the control room operators of the test evolution and the EOI requirements was excellent. No testing deficiencies other than thos discussed above were observed by the inspectors.

g. 2-TI-191, Feedwater Pump Trip

The inspectors observed the performance of this TI on July 29, 1991, following the completion of 2-TI-132. The reactor power level was increased to approximately 94.5% full power for the test. The purpose of the test was to acquaint Operations personnel with the integrated plant response to a trip of one reactor feedwater pump. The response of the reactor recirculation system was monitored to demonstrate the capability to prevent a low water level scram in the event water level decreased to a point where the automatic recirculation runback circuit was activated to decrease reactor power to within the capability of the remaining two feedwater pumps.

Thorough briefing of Operations and test personnel by the test director were observed by the inspectors. The testing was performed smoothly, but the automatic recirculation runback circuit was not activated due to the response of the running feedwater pumps to maintain water level above the 27" actuation setpoint during the transient. A test deficiency was declared and the test results were investigated. Review of transient data indicated that water level decreased to only 27.5", but observation of the SPDS indicated that water level was reduced below 25". The licensee planned to perform additional testing of the runback circuitry to ensure that the setpoints were correct and that the system would have responded as designed. The difference between the water level observed on the SPDS and the water level based on the transmitter output feeding the runback circuit was also being investigated. Reperformance of the test was not anticipated. No other testing deficiencies were observed.

h. 2-TI-193, Turbine Trip and 2-TI-180, Backup Control Panel Testing

The inspectors observed the performance of these TIs August 2, 1991. The tests were initiated from a power level of approximately 45%. The purpose of the tests was achieved by initiating a plant shutdown by operator performance of a turbine trip, resulting in a reactor scram. Following stabilization of plant conditions, a test crew of operators proceeded to the shutdown control panel and to local plant control panels and shutdown boards and demonstrated the capability to control reactor pressure and water level via the shutdown board control of safety relief valves and the RCIC system. Cooldown and depressurization was continued until a cooldown of 45 degrees F was achieved over a 30 minute or greater time period to demonstrate adequate operator control from the backup control panel. Control of other plant systems was maintained from the main control room. Water level and pressure control was returned to the main control room following completion of activities from the remote stations.

The test crew and the onshift operating crew attended t aining sessions consisting of inplant walkdowns and simulator demonstrations in preparation for the tests. The inspectors attended one of the training sessions and observed their value in identifying potential problem areas. A test briefing was conducted by the test director and was observed to be thorough and comprehensive. Additional discussions on equipment alignments and operator personnel assignments were held immediately following the briefing. No deficiencies were observed in the conduct of the testing.

i. Set Electrical/Mechanical Recirc Control Stops, SII-2-SE-96-3

Surveillance Instrument Instruction, SII-2-SE-96-3, was performed to adjust and limit the speed on the reactor recirculating water pumps. The limit was set at recirculation flows equal to an approximate 102% power level. It was accomplished by limiting the variable speed on the generator sets which supply power to the pumps. This was successfully completed on the second effort after a procedural error was found and corrected after the first attempt. The inspectors reviewed this effort while in progress and determined that the activity was accomplished within the guidelines of the procedure.

4. Power Ascension Test Program Review (72301, 72532)

The inspectors reviewed testing performed in accordance with 2-SOI-100-1, Master Startup Operations/Testing Instruction. The inspectors performed a review of TDs recorded during performance of the TIs comprising the PATP, and noted several TDs that required further evaluation by the licensee as follows.

a. 2-TI-131 Feedwater Level Control System

This TI adjusted the feedwater control system for satisfactory water level control, and ultimately will verify that components of the feedwater control system can control reactor water level satisfactorily. After initial controller adjustments were made per the TI, the procedure was completed with no difficulties encountered in maintaining adequate level control at low power levels. However, the time response to insertion of a manual step (5 and 10% change) in feed flow still failed to meet Level 2 response criteria. Notwithstanding, a decision was made to proceed with the test program, and perform additional feed pump tuning at a higher power (about 58%) level.

Additional feed pump tuning was accomplished at a higher power level, but the time response of individual feed pumps to insertion of manual steps (5 and 10%) did not meet acceptance criteria.

Technical support engineers acknowledged that the response times of individual feedpump turbines is slower than Level II test acceptance criteria and FSAR commitments, however they also concluded that the overall response of the feedwater control system in single and three element control was adequate to safely support continued operation; further evaluation and review is ongoing.

Based upon the overall system response and observation of daily operations, the inspectors concluded that this TD did not adversely affect continued power operations.

b. 2-TI-174 Recirculation System Flow Calibration

The purpose of this test was to perform a calibration of the installed recirculation system flow instrumentation at near-rated conditions. The test was performed four times at four different flows. Test results failed to meet acceptance criteria in two categories of deficiencies.

The first category of deficiencies was the failure to meet acceptance criteria. During the conduct of the test, the core flow calculated by the test did not agree, within plus or minus one Mlb/hr, with the core flow as read on meter 2-FR-68-50, Total Core Flow, on Panel 2-9-5, or with the core flow value obtained from the process computer OD-3 op-2 edit program. The single loop proportional amplifiers, FM-68-45 and FM-68-47, and total core flow meter, 2-FR-68-50, were recalibrated, but the acceptance criteria was still not met. The closest values received were:

Calculated core flow	99.7 Mlb/hr
Process Computer OD-3	101.46 Mlb/hr
Meter 2-FR-68-50	101.5 Mlb/hr

The licensee noted during the last test that the calculated core flow appeared low based on the fact that the Loop A flow was low. However, there was no identified corrective action or information to support that conclusion. This deficiency requires further resolution.

The second category of deficiencies was caused by inconsistent results (i.e., lack of repeatability). For example:

(1) The GAF calculated for the APRM/RBM loop proportional amplifiers and the GAFs calculated for the single tap loop proportional amplifiers were not consistently between 0.99 and 1.01, which was the acceptance criteria for these calculations. The GAFs were acceptable during the first test, but some were outside the acceptance criteria limits on the second test and others were outside the acceptance criteria limits during the third test. In some cases the amplifier had not even been adjusted between tests. Test results were satisfactory in one test, but not in the subsequent test, i.e. inconsistent results. The licersee noted that the probable cause of the inconsistent GAFs for the proportional amplifiers was due to noise in the measured signal circuits. This deficiency requires further resolution.

(2) The calculated nozzle plugging criteria was at the acceptance criteria limit for one set of jet pumps and exceeded the acceptance criteria limit for another set of jet pumps during the last test. The nozzle plugging criteria had been met during previous tests, i.e. inconsistent results. The licensee noted that the probable cause of the unacceptable calculated nozzle plugging criteria was noise in the measured signal, which resulted in incorrect values being recorded. Since satisfactory results had been obtained during previous performances of this test, the licensee concluded the test results were a one time occurrence and no further action was necessary.

None of the deficiencies noted during the test violated or exceeded any TS limits, and all the deficiencies involved Level 2 Criteria. The inspector concluded that the deficiencies did not adversely affect continued plant operation. However, the core flow and GAF calculation deficiencies need to be resolved. There may be equipment problems causing the circuit noise or procedure changes necessary to eliminate these type of deficiencies and accurately monitor these parameters.

c. 2-TI-189, High Pressure Coolant Injection System

This test verified proper HPCI system operation, including a manual start to verify system parameters and absence of leaks, a hot "quick" start, and a cold "quick" start (the latter is a simulation of conditions for an emergency injection). Two TDs requiring further evaluation were documented during this test.

(1) During initial startup of the HPCI turbine from cold conditions (at 150 psig), the HPCI turbine stop valve exhibited a rapid opening, closing and re-opening. This valve action was not inconsistent with expected system response during cold, "jack-rabbit" starts addressed in the system operating instruction and GE advisory information SIL No. 352), indicating too low a balance chamber adjustment. The HPCI turbine stop valve performed satisfactorily during tests at rated reactor pressure.

(2) During HPCI flow tests to the reactor vessel at normal operating pressure, step changes in flow demand (3,000 to 2,500 gpm) exhibited a decay ratio of 0.60 (test criteria <0.25). Acceptable decay ratios were exhibited for step changes at full flow (5,000 to 4,500).

The licensee evaluated these TDs as not adversely affecting the HPCI system performance because the deficiencies were observed during conditions other than normal expected conditions (i.e., low pressure, low flow). Nevertheless, the licensee continued its evaluation of the test data.

Based upon observation of nominal system performance at design conditions, the inspectors concluded that these HPCI system TDs did not adversely affect continued power operations. However, the inspectors also noted that HPCI operation may be required at other than normal operating pressure and/or full flow, thus the TDs must be evaluated further.

The licensee will submit a final report to the NRC within 60 days after completion of the PATP. This report will contain the final disposition of TDs. The inspectors will review this report when received.

5. Operational Safety Verification (71707)

General plant tours were conducted. Portions of the turbine buildings, each reactor building, and general plant areas were visited. Observations included valve position and system alignment, snubber and hanger conditions, containment isolation alignments, instrument readings, housekeeping, power supply and breaker alignments, radiation and contaminated area controls, tag controls on equipment, work activities in progress, and radiological protection controls. Informal discussions were held with selected plant personnel in their functional areas during these tours.

During a routine tour on July 28, 1991, the inspector identified several problem areas around the outside of the reactor building and intake structure. These items were immediately discussed with the SOS on July 28, 1991, and other plant management on July 29, 1991.

a. Fallen Unit Separation Signs

Several Unit 2 Operating Space signs had fallen down. These signs were placed at various locations in the plant as part of the Unit 2/ Unit 3 separation program. Examples were one of the outside doors for the Unit 1/2 DG doors, Unit 1 reactor building ventilation intake, and mechanical equipment room A (door 830). This indicated a need for periodic inspection and maintenance for the separation program. The signs have orange lettering on a black background. Due to rain the orange lettering had been washed out of several signs leaving white lettering on a black background.

b. Smoking In No Smoking Areas

The inspector observed that a temporary machine shop had been erected on top of the Unit 3 DG building. At each entrance to the roof were No Smoking Signs specifically stating to not smoke on the DG building roof. There was evidence of an estimated 50 to 100 cigarette butts on the roof indicating a blatant disregard of the No Smoking Signs.

c. Fire Wrap Removal From Operating Equipment

In the intake structure the inspector identified that fire wrapping around power cable junctions boxes for the RHRSW pumps had been removed. All of the pumps were operable at the time. The fire wrap is used to provide a one hour fire resistance barrier rating between redundant safe shutdown equipment. The two electrical divisions of RHRSW power cables do not meet the minimum separation distance of 20 feet, and the fire wrap is required. One division is routed in a cable tray tunnel and the other division routed in a conduit tunnel. The RHRSW pumps provide cooling as the ultimate heat sink at BFNP. If for some valid reason the fire wrap is removed, a fire watch is required to be posted within one hour. The inspector knew of no reason this should be removed because of the operable equipment. The inspector reviewed the listing of fire protection active impairment permits called Attachment F to FPP-2. No permits or compensatory actions were in effect for the fire wrap.

Upon notification the SOS took immediate action to correct the problem. An Attachment F was completed and a fire watch posted. Licensee senior management was contacted and a detailed action plan initiated to identify and correct the problems. It was determined that the fire wrap was removed under WO 91-35664-00 to support Unit 3 walkdown inspections. The WO was approved by the Operations Work Control Group on July 17, 1991. The licensee stopped all Unit 3 walkdown inspections until the problems were fully identified and corrected.

The inspector concluded that a violation of TS 3.11.G.1.a had occurred. This requires that all fire rated assemblies such as conduit wraps separating systems important to safe shutdown within a

fire area shall be operable at all times. If the assembly device is inoperable a fire watch must be established within one hour. This was identified as VIO 259,260,296/91-26-02, Fire Wrap Inappropriately Removed.

Later the licensee determined that the contractor preparing the walkdown inspection plan did not use the Unit 2/Unit 3 separation drawings. This would have prevented walkdowns in this area. The licensee at the end of this report period had not resumed work and still was developing their corrective action plan. These issues will be followed during the routine resident inspections prior to resuming work activities, and violation closure.

d. Unit 3 Fuel Sipping and Inspections

During this reporting period, the licensee conducted fuel sipping and inspection of fuel assemblies located in the Unit 3 SFSP. The purpose of these activities was to assess the condition of fuel for possible use in Unit 3 cycle 6 by identifying failed fuel a semblies. The sipping and inspection were conducted by GE personnel. The inspectors reviewed and observed these activities on an ongoing basis during the reporting period. No deficiencies were identified with the fuel inspection activities; however, fuel handling errors were made during fuel sipping operations.

Fuel sipping was performed in accordance with special test 3-ST-90-03, Unit 3 Fuel Sipping. Two fuel sipping cans were utilized and were addressed as the "north" and "south" sipping cans. Fuel assembly transfer forms were prepared and approved for each fuel movement in the SFSP. Procedure SDSP 26.1, Special Nuclear Material Management, establishes the administrative requirements for the handling of SNM and the transfer of SNM from one item control area to another. Because the Unit 3 SFSP is considered as a single "Item Control Area," the requirements for second party verification of fuel assemblies were not in place. Fuel assembly identification was being performed by SFSP row-rack-column location only.

Procedure 3-ST-90-03 required that fuel handling be performed in accordance with 3-GOI-100-3, Refueling Operations, and the approved FATFs for moving fuel assemblies between the sipping cans and their SFSP locations. Procedure 3-GOI-100-3 required that all steps on the FATFs be performed line by line. The fuel handling errors were as follows:

(1) On June 29, 1991, the fuel handlers grappled a fuel assembly from a different SFSP location than that identified on the approved FATF. The fuel assembly was moved to the south sipping can. After the assembly was sipped the fuel handlers attempted to place it in the position called for on the FATF. Upon finding that SFSP location occupied, all fuel handling was stopped and the refueling SRO was notified. The licensee

conducted an incident investigation (II-B-91-130) which concluded that the event was caused by personnel error and failure to follow procedures. Immediate corrective actions included verifying that surrounding fuel assemblies were in their proper locations; initiating a field change to place the errant fuel assembly in its proper location; and conducting a briefing on the importance of verifying correct SFSP locations. In addition to these corrective actions, the licensee also implemented first and second party verification of both the fuel assembly serial number and SFSP location during the remaining fuel moves.

(2) On July 6, 1991, the licensee identified that a fuel assembly was placed in SFSP location 05-10-G instead of 05-10-F as designated on the FATF. The licensee determined that the error occurred when the assembly was being moved from the south sipping can to its SFSP location. A second error then occurred when the fuel assembly serial number was incorrectly identifed and the incorrect assembly was returned to the south sipping can. A third error occurred when the fuel assembly in the north sipping can was placed in SFSP location 05-10-F instead of 05-10-G. All fuel handling was stopped and the licensee initiated an incident investigation (II-B-91-132). The investigation concluded that the mistake was caused by personnel error and failure to follow procedures. The licensee took immediate corrective actions in response to these errors which included comparing the SFSP storage racks to the FATFs; field changes to place the fuel assemblies in the correct SFSP locations; counselling fuel handlers on the importance of second party verification; placing a supervisor on the fuel handling bridge to monitor operations; and establishing an operator aid to formalize communications between the bridge and the fuel handling SRO. In addition, personnel disciplinary actions were taken against the individuals involved.

The failure to follow steps on the FATFs line by line is a violation of TS section 6.8.1.1 for the failure to implement procedures (VIO 296/91-26-03, Fuel Handling Errors). The inspectors are concerned by these fuel handling errors and the apparent ineffectiveness of the corrective actions for the first event.

6. Procurement (38702)

The inspector reviewed information from Connex Pipe Systems Inc., forwarded by Region III, that BFN had received 12 one and one half inch socket weld unions and three 150 lbs. pipe flanges, which were processed as B31.1 non-nuclear instead of under Connex's ANSI N45.2 program. The unions were shipped on BFN order 90NJS-82557C and the pipe flanges on 91NJA-82667C. The licensee initiated CAQR BFP 910110, dated April 4, 1991, which indicated that the material was received without adequate

documentation. The CAQR also indicated that Connex was contacted about the deficiency.

The inspector reviewed the following items: DCN W457A, which added two pieces of one-and-one-half-inch diameter pipe, each two feet long, to the demineralized water supply for the RHR heat exchangers, and was done for stress reduction in order to enhance the ability of the RHRSW piping to maintain a Seismic Class I boundary; MR 891015103, which replaced flanged fittings on drywell cooler A5 inlet and outlet which is part of the RBCCW system; QDCN Q16640A, which indicated that the use of a B31.1 union in the nonsafety-related DI water system was acceptable; and QDCN Q1667A, which indicated that an ASTM B-61 was an acceptable material in accordance with ANSI B 16.24, Bronze Pipe Flanges and Flanged Fitting, for the flanges installed on drywell cooler A5 inlet and outlet.

The inspector concluded from these reviews that the material was shipped from Connex without the proper vendor QA reviews and approvals, BFN receipt inspection initially identified the problem, the material was used in the RBCCW and DI systems, and the use of the material was acceptable.

7. 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 296/91-02, Unplanned ESF Actuation Following Deenergization of RPS Bus By Unknown Cause.

On April 5, 1991, an unplanned ESF actuation occurred upon the loss of RPS Bus 3B. The bus deenergized when the 3B1 circuit protector tripped. All equipment responded as designed to the ESF signal. The cause of the event could not be determined.

An inspector reviewed the LER, dated May 5, 1991, and determined that it met the requirements of 10 CFR 50.73. The inspector also reviewed the incident investigation which was conducted on this event (II-B-91-078). The investigation did not discover any failed components or plant conditions which could have caused the circuit protector to trip. However, during troubleshooting on the circuit protector internal components, the overvoltage relay setpoint jumped from 129.7 volts to 131.4 volts and then continued to repeat in the range of the higher value. Even though this test did not indicate failure of the overvoltage relay, it was replaced for conservatism. No discrepancies or concerns were identified during the review of this LER.

b. (CLOSED) LER 259/91-03, Gaseous and Liquid Effluent Samples That Were Missed Due To Improper Work Activities Caused TS Requirements To Be Exceeded.

On March 1, 1991, the licensee discovered that security data could not support the performance of effluent samples for two inoperable radiation monitors. Based on this finding, the licensee determined that TS required compensatory measures were not implemented.

An inspector reviewed the LER, dated April 1, 1991, and determined that it met the requirements of 10 CFR 50.73. A violation was issued for this event (VIO 91-10-02) in a previous NRC report. The follow-up of the violation and associated corrective actions are discussed in paragraph 8 of this report. No further concerns were identified during the review of the LER.

c. (CLOSED) LER 296/91-03, Unplanned ESF Actuation Unit 3 DGs Started

On April 12, 1991, an unplanned ESF actuation occurred when the four Unit 3 emergency DGs unexpectedly auto-started during the performance of the common accident signal logic SI. The cause of this event was personnel error resulting from a lack of attention to detail during installation of an inhibiting boot between two contacts on the Division II core spray logic B relay.

Corrective actions performed included Operations personnel ensured that electrical maintenance personnel stopped the performance of the SI; an incident investigation was conducted to determine the cause of the event; and the SI was resumed and successfully completed. Maintenance personnel who install boots received training on the proper installation of boots.

The inspector reviewed the LER and supporting documentation which included electrical maintenance training records and incident investigation No. B-91-091 dated June 13, 1991. Based on this review the inspector concluded that adequate corrective action was taken.

d. (CLOSED) LER 259/91-05, Potential Failure of RHRSW and EECW Systems Following A Seismic Event

On April 12, 1991, the licensee determined that a previously recognized condition had not been reported in accordance with the requirements of 10 CFR 50.73. This condition involved the potential for failure of the RHRSW and EECW Systems during a seismic event. In July 1987, during performance of hydrostatic testing of RHRSW piping, a flexible joint, Dresser coupling failed due to excessive axial load. Subsequently, on December 5, 1987, a condition adverse to quality report was written to document that protection of buried piping from differential movement of the soil and building structures was not achieved because none of the existing flexible joint designs could have accommodated differential movement in the direction along

the axis of a the pipe. This was the result of a rigid connection called a saddle which was installed across the flexible joint to prevent pressure loads from pulling apart the piping from the joint. As a result of this design, a seismic event could have caused loss of RHRSW and EECW. This condition existed since original construction of the plant.

The inspector reviewed the LER and supporting documents. The corrective action was consistent with the commitments in Volume 3 of the NPP. Programs were established to resolve past deficiencies which led to inadequately documented or analyzed designs. At the requirements for these programs were developed and implemented. Project instructions were also issued which augment the requirements of the programs. TVA added a section to the Rigorous Analysis Handbook which established guidelines for design and analysis of flexible joints. A clarifying statement was also added to a design criteria that established requirements for analysis of flexible joints. Based on this review the inspector concluded that adequate corrective action was taken.

e. (CLOSED) LER 260/91-07, ESF Actuation Resulting from Leaking Packing on the DP Transmitter.

This item was identified on April 9, 1991 when an unplanned ESF actuation occurred. A Group 1 PCIS occurred during the performance of a SI when IMs placed Channels A and B in an isolated mode and a leak from 2-PDT-1-25B valve caused the depressurization of the low side of the Channel B transmitter. The cause of this event was that one process instrument had entrapped air in the low-side sensing line, and one process instrument had a water leak from the packing in the low-side manifold valve. Both instruments were part of the MSL, high flow logic.

The unit operator contacted in the IMs, and work on the SI was stopped. The IMs returned the affected instruments to service. Subsequent corrective actions were the IMs vented trapped air; backfilled line for the first process instrument; and tightened packing nuts on the other process instrument. In addition, SIs that test excess flow check valves were revised to require constant communications with control room Unit Operator and to install jumpers to bypass the initiation of Group 1 PCIS logic on main steam line high flow.

The inspector reviewed the licensee corrective action. It was also noted that the SI, 2-SI-4.7.D.1.d-2, Instrument Line Flow Check Valve Operability Test, was resumed with no additional problems.

f. (CLOSED) LER 260/91-12, Unplanned ESF Actuation Following RPS Bus Deenergization Caused By Random Equipment Failure.

On May 19, 1991, an unplanned ESF actuation occurred upon the loss of RPS Bus 2A. All equipment responded as designed to the ESF signal. The cause of the event was the failure of the RPS Bus 2A normal power source, MG set 2A.

An inspector reviewed the LER, dated June 17, 1991, and determined that it met the requirements of 10 CFR 50.73. The inspector also reviewed the incident investigation conducted for this event (II-B-91-112). The investigation attributed the motor failure to a breakdown of the winding insulation. There was no history of motor failures by this method at BFN and this was considered an isolated event. The licensee replaced the failed motor and returned the MG set to service. No discrepancies or concerns were identified during the review of this LER.

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

a. (CLOSED) IFI 259, 260, 296/89-35-01, Flexibility of Reactor Water Level Sensing Lines.

This item addressed the inspector's concerns in two areas associated with the replacement of a flexible instrument piping system on the reactor water level sensing lines on Unit 2 with a one-inch rigid stainless steel piping: The first concern involves the need for preventative maintenance and the second deals with setting the spring-can hangers for operating temperatures ("hot setting").

The licensee's corrective actions included an evaluation and determination that the system has been installed properly and that no prescheduled preventative maintenance activities are required. However, the system engineers are required to walkdown their respective systems periodically to evaluate the need for maintenance. The actions to disposition the second part of the issue were completed when the spring cans were evaluated and adjusted as required during the performance of TI-190, Thermal Expansion, with the reactor at operating temperature and pressure.

Based on the above actions taken by the licensee, this issue is closed for Unit 2. However, the item is administratively closed for Units 1 and 3 since it was opened based on concerns associated with the corrective actions for Unit 2 only.

b. (CLOSED) VIO 259, 260, 296/91-10-02, Missed Compensatory Samples.

This violation was issued for the failure to implement TS compensatory measures. On March 1, 1991, the licensee discovered that security data could not support the performance of effluent samples for two inoperable radiation monitors. Based on this finding, the licensee determined that TS required compensatory measures were not implemented.

The licensee initiated an incident investigation (II-B-91-045) to determine the root cause of the event and corrective actions to be taken. The investigation determined that the causes of the event included failure to follow sampling procedures, the misuse of checklists, and inadequate chemistry supervision. The corrective actions included personnel actions against the chemistry analysts involved; discussions with all chemistry personnel of strict procedural compliance and the meaning of initials/signatures in procedures; and revisions to procedures for the oversight of compensatory SIs.

An inspector reviewed the licensee's response to this violation the completed incident investigation, and revised chemistry SIs. The inspector determined that the corrective actions had been completed. No discrepancies or concerns were identified during the review of this item.

c. (CLOSED) VIO 259, 260, 296/91-17-01, Failure to Follow Hold Order Procedure.

The licensee had failed to follow SDSP-14.9, Equipment Clearance Procedure, in that an independent verification of the clearance boundary was not performed prior the placing the hold tags on the applicable equipment. The boundary was that utilized to isolate Units 1 and 3 from Unit 2 for the restart of Unit 2. The licensee stated that the tag-out was an extremely large boundary that involved several systems and was being initiated and verified on a system by system basis rather than the entire tag-out being identified and verified and signed-off prior to the placement of any tags on the equipment as required by the procedure.

This issue was identified by the inspector and once the licensee was confronted, changes were made to the tagging process to meet the requirements of the procedure. Based on this corrective action, this item is therefore closed.

d. (CLOSED) Open Item 260/91-202-01, Inadequate Review of Plant Conditions Prior To Beginning Surveillance Test.

During the NRC ORAT followup inspection, an inspector identified a concern with inadequate Operations shift supervision over the performance of an SI. A UO had to stop the performance of O-SI-4.2.B-67, RHR Service Water Initiation Test, when it was realized that continuing would reduce the number of operable RHRSW pumps below that required by TS. The procedure required a EECW pump to be made inoperable; however, the other EECW pump on the same header was already inoperable for reasons not related to the SI. The inspector considered this an example of inadequate supervision in that off-normal conditions were not considered prior to authorizing the performance of the SI. The inspector discussed this item with

licensee management and the Operations Manager stated that the following corrective actions would be taken:

(1) Discuss with shift supervision the importance of properly assessing plant status prior to authorizing SIs.

(2) Revise the SI to assure that TS pump requirements cannot be inadvertently violated.

During this reporting period, an inspector reviewed the licensee's closure package for this item and the revised SI. The inspector concluded that the licensee had completed corrective actions which should preclude the recurrence of this issue. No discrepancies or concerns were identified during the review of this item.

9. Exit Interview (30703)

The inspection scope and findings were summarized on August 16, 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
260/91-26-01	NCV, Failure to Update Control Room Procedure, paragraph 2.
259,260,296/91-26-02	VIO, Fire Wrap Inappropriately Removed, paragraph 5.
296/91-26-03	VIO, Fuel Handling Errors, paragraph 5.

Licensee management was informed that 6 LERs, 1 IFI, 2 VIOs, and 1 ORAT Item were closed.

10. Acronyms and Initialisms

ANSI	American National Standards Institute
APRM	Average Power Range Monitor
ASOS	Assistant Shift Operations Supervisor
BFNP	Browns Ferry Nuclear Plant
CAQR	Condition Adverse to Quality Report
CFR	Code of Federal Regulations
DCN	Design Change Notice
DCRM	Document Control and Records Management
DG	Diesel Generator
DP	Differential Pressure
ECCS	Emergency Core Cooling Systems

ECCW	Essential Component Cooling Water
EECW	Emergency Equipment Cooling Water
ENS	Emergency Notification System
EOI	Emergency Operating Instruction
ESF	Engineered Safety Feature
FPP	Fire Protection Procedure
FSAR	Final Safety Analysis Report
GAF	Gain Adjustment Factor
GE	General Electric
GOI	General Operating Instructions
GPM	Gallons Per Minute
HPCI	High Pressure Coolant Injection
IFI	Inspector Followup Item
IM	Instrument Maintenance/Mechanics
IR	Inspection Report
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LRED	Licensee Reportable Event Determination
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
MSL	Main Steam Line
M&TE	Measuring and Test Equipment
NCV	Non-cited Violation
NOV	Notice of Violation
NPP	Nuclear Performance Plan
NRC	Nuclear Regulatory Commission
OI	Operating Instruction
PATP	Power Ascension Test Program
PCIS	Primary Containment Isolation System
POB	Plant Operations Building
Psig	Pounds Per Square Inch Guage
QA	Quality Assurance
QC	Quality Control
QDCN	Quality Design Change Notice
RBCCW	Reactor Building Closed Cooling Water
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RPS	Reactor Protection System
SDSP	Site Director Standard Practice
SI	Surveillance Instruction
SIL	Service Information Letter
SOI	Special Operating Instruction
SPDS	Safety Parameter Display System
TD	Test Deficiency
TI	Technical Instruction
TIC	Technical Information Center
TS	Technical Specifications
TVA	Tennessee Valley Authority

UIC	Urgent Intent Change
UO	Unit Operator
URI	Unresolved Item
VIO	Violation
WO	Work Order
WP	Work Plan
WR	Work Request