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

Report Nos.: 50-259/85-06, 50-260/85-06, and 50-296/85-06

Licensee: Tennessee Valley Authority
500A Chestnut Street
Chattanooga, TN 37401

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: December 26, 1984 - January 25, 1985

Inspectors: Linda J Watson for G. L. Paulk, Senior Resident Inspector	3/1/85 Date Signed
Linda J Watson for C. A. Patterson, Resident Inspector	3/1/85 Date Signed
Approved by: F. S. Cantrell, Chief, Section 1B, Division of Reactor Projects	3/5/85 Date Signed

SUMMARY

Scope: This routine, unannounced inspection entailed 154 inspector-hours in the areas of operational safety, maintenance observation, surveillance observations, reportable occurrences, reactor trips and regulatory improvement plan. There were five violations identified as noted below:

(1) Technical Specification (TS) 3.7.D.1 - Core Spray isolation valve (FCV-75-26) inoperable during power operation on January 21, 1985.

(2) 10 CFR 50, Appendix B, Criterion V - Inadequate drawings and procedures and failure to follow procedures with five examples:

a. Surveillance Instruction (SI) 3.2.2 - Motor Operated Valve (MOV) Cycling During Cold Shutdown, was inadequate in that no signoff or steps were included to address placement and removal of temporary test hoses used to bypass testable check valves.

b. SI 3.2.2 - was not adhered to in that the correct indication of method used to test the testable check valves was not noted correctly on the data sheets.

c. SI 4.5.E.2.d/e - High Pressure Coolant Injection (HPCI) Flow Test (Auxiliary Steam) was inadequate to verify HPCI operability without valve timing requirements included.

d. SI 4.5.E.1.d/e - HPCI Flow Test (Nuclear Steam), was inadequate, since timing between the start of system initiation and meeting design flow rate in 25 seconds was not verified as per Final Safety Analysis Report (FSAR) Section 7.4.

e. Drawing (DWG) 45N714-2 - had an error incorporated in it related to HPCI limit switch settings.

(3) 10 CFR 50, Appendix B, Criterion XVI - failure to adequately control the certifiability required for surveillance thermometer requisitions as required by Browns Ferry Standard Practice 17.19 (BF 17.19).

(4) TS 3.5.E.1.(2) - HPCI was not operable on Unit 3 from December 9, 1984 - January 11, 1985, due to inability to meet design or surveillance requirements for the proper timing of the HPCI start sequence.

(5) TS 3.1.A - Intermediate Range Monitor (IRM) hi flux scram was inoperable, since only two IRM channels were operable on the Reactor Protection System (RPS) "A" trip system for Unit 1 on January 18, 1985.

An enforcement conference to discuss these violations was held February 7, 1985 (Inspection Report 50-259/85-12, 50-260/85-12 and 50-296/85-12).

REPORT DETAILS

1. Licensee Employees Contacted

J. A. Coffey, Site Director
G. T. Jones, Plant Manager
J. E. Swindell, Superintendent - Operations/Engineering
J. R. Pittman, Superintendent - Maintenance
J. H. Rinne, Modifications Manager
J. D. Carlson, Quality Engineering Supervisor
D. C. Mims, Engineering Group Supervisor
R. Hunkapillar, Operations Group Supervisor
C. G. Wages, Mechanical Maintenance Supervisor
T. D. Cosby, Electrical Maintenance Supervisor
R. E. Burns, Instrument Maintenance Supervisor
A. W. Sorrell, Health Physics Supervisor
R. E. Jackson, Chief Public Safety
T. L. Chinn, Technical Services Manager
T. F. Ziegler, Site Services Manager
J. R. Clark, Chemical Unit Supervisor
B. C. Morris, Plant Compliance Supervisor
A. L. Burnette, Assistant Operations Group Supervisor
R. R. Smallwood, Assistant Operations Group Supervisor
T. W. Jordan, Assistant Operations Group Supervisor
S. R. Maehr, Planning/Scheduling Supervisor
G. R. Hall, Design Services Manager
W. C. Thomison, Engineering Section Supervisor
A. L. Clement, Radwaste Group Controller

Other licensee employees contacted included licensed reactor operators, senior reactor operators, auxiliary operators, craftsmen, technicians, public safety officers, Quality Assurance (QA), Quality Control (QC) and engineering personnel.

2. Exit Interview (30703)

The inspection scope and findings were summarized on January 25, 1985, with the Plant Manager and/or Assistant Plant Managers and other members of his staff.

The licensee acknowledged the findings and took exception to the violation which noted IRM inoperability. The Plant Manager considered that action statement 1A was being met. This item is discussed in detail in paragraph 5.

The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection, with the exception of the steam acoustic monitor electrical circuit design details. The proprietary portions of the circuits are not addressed in this report.

3. Licensee Action on Previous Enforcement Matters (92702)

   a. (Closed) Violation (259/83-18-02) - Fuel Transfer Procedures not followed during Unit 1 reload (Technical Instruction (TI) 14). TI-14 was revised to require that a field change request involving fuel movement be made on a separate field change sheet. This event was discussed with operators to clarify fuel handling activity requirements. This item is closed.

   b. (Closed) Violation (259, 260, 296/83-19-01) - Valve lineup procedures were inadequate to align the condensate system to the residual heat removal system to assure maintenance of filled discharge piping. The system status files were updated to reflect actual system status. The pressure suppression chamber charging system was made operational on all three units. This item is closed.

   c. (Closed) Violation (259, 260, 296/83-23-02) - Mechanical Maintenance Instruction 116 (MMI-116) used to verify vital area door condition was not conducted as required. MMI-116 was revised to include all vital area doors. MMI-116 was performed after revision to ascertain all vital area doors met operability requirements. This item is closed.

   d. (Closed) Deviation (259, 260, 296/83-27-10) - Safety wires not installed on backup control panels (BCP), and BCP performance cycle tests were not performed as required. The Final Safety Analysis Report (FSAR) will be updated to delete the requirement for safety wire installation. The BCP will be tested as required during each refueling outage. A new TI was written to accomplish this task. This item is closed.

   e. (Closed) Violation (259, 260, 296/83-46-04) - Revisions to safety evaluations were not adequately reviewed by the Plant Operating Review Committee (PORC). Standard Practice 8.3 was updated to require flagging of unreviewed safety question determination (USQD) special requirements for PORC review. Workplan closeout further verifies that stated special requirements have been met. This item is closed.

   f. (Closed) Violation (259, 260, 296/83-55-01) - Failure to report Diesel Generator and Emergency Equipment Cooling Water (DG/EECW) design inadequacies. The licensee failed to recognize this item as reportable. The new reporting rule clarifies reporting requirements. This item is closed.

   g. (Closed) Violation (259, 260, 296/83-55-02) - Design deficiency during original design of EECW system. TVA, in designing the EECW, assumed that the equipment being supplied by General Electric utilizing EECW was rated for operation at the EECW system pressure. As such, this interface was overlooked at the design review stage. This item is closed.

h. (Closed) Violation (259, 260/83-60-01) - Numerous work activities were not adequately completed to return systems to the as-configured installation after the outage. All deficiencies were corrected, and a detailed walkthrough was conducted on all units to note and correct similar discrepancies. Standard Practice 12.18 was revised to provide more detailed guidance on houskeeping inspections. Appropriate personnel have received training on housekeeping inspections. This item is closed.

i. (Closed) Violation (259/83-60-05) - Failure to follow tagout procedures. The clearance procedure (BF 14.25) has been revised to include two-part verification on return to service of safety or safety-related systems when a clearance is released. This item is closed.

4. Unresolved Items (92701)

There were no new unresolved items this report period.

5. Operational Safety (71707, 71710)

The inspectors were kept informed on a daily basis of the overall plant status and any significant safety matters related to plant operations. Daily discussions were held each morning with plant management and various members of the plant operating staff.

The inspectors made frequent visits to the control rooms such that each was visited at least daily when an inspector was on site. Observations included instrument readings, setpoints and recordings; status of operating systems; status and alignments of emergency standby systems; onsite and offsite emergency power sources available for automatic operation; purpose of temporary tags on equipment controls and switches; annunciator alarm status; adherence to procedures; adherence to limiting conditions for operations; nuclear instruments operable; temporary alterations in effect; daily journals and logs; stack monitor recorder traces; and control room manning. This inspection activity also included numerous informal discussions with operators and their supervisors.

General plant tours were conducted on at least a weekly basis. Portions of the turbine building, each reactor building and outside areas were visited. Observations included valve positions and system alignment; snubber and hanger conditions; containment isolation alignments; instrument readings; housekeeping; proper power supply and breaker alignments; radiation area controls; tag controls on equipment; work activities in progress; radiation protection controls adequate; vital area controls; personnel search and escort; and vehicle search and escort. Informal discussions were held with selected plant personnel in their functional areas during these tours.

Weekly verifications of system status which included major flow path valve alignment, instrument alignment and switch position alignments were performed on the standby liquid control and core spray systems. A complete walkdown of the accessible portions of the high pressure coolant injection system was conducted to verify system operability. Typical of the items checked during the walkdown were that: lineup procedures match plant drawings and the as-built configuration, hangers and supports were operable; housekeeping was adequate; electrical panel interior conditions were adequate; calibration dates were appropriate; system instrumentation was on-line; valve position alignment was correct; valves locked as appropriate; and system indicators functioned properly.

a. Standby Liquid Control test valves, as installed, were reversed - Unit 3

On January 15, 1985, the inspectors were informed that two 3/4-inch test valves in the Unit 3 Standby Liquid Control System (SLC) were discovered to be installed improperly. The valves (3-63-528 and 3-63-529) are installed in a test line between the Primary Containment Isolation Check Valves in the SLC injection piping and are normally locked closed. The valves were found to be installed in the reverse direction of their design flow path and apparently had been in this condition since initial installation. A Safety Evaluation Report was performed by the Engineering Design Group which concluded that the condition did not create any adverse effects on plant operation. Corrective action to remove and reinstall the valves per design orientation is scheduled for the next refueling outage. The inspectors reviewed the Failure Investigation Report and the Safety Evaluation Report and took no exceptions.

b. Core Spray System weld crack - Unit 1

On January 8, 1985 a leak was discovered on the FCV 1-75-22 bottom drain pipe nipple while performing a routine pump operability surveillance. FCV 1-75-22 is the Unit 1 Core Spray System full flow test valve; a normally closed valve which is throttled open to direct Core Spray Pump discharge to the torus and establish the required discharge head during pump performance surveillance. The leak was located at the bottom drain pipe nipple weld at the lower valve body. Plant personnel considered TS 3.7.A.2.C (Containment nitrogen makeup limitation) applicable which allows eight hours to correct the situation or the reactor be placed in hot shutdown within the next 16 hours. The pipe was cut out and replaced by 1130 the same day.

Since this valve was used to vent the Core Spray System during the Core Spray Overpressurization event on August 14, 1984, (refer to Inspection Report 84-34) the inspectors notified plant management of their concern regarding a failure analysis of the weld. The inspectors were informed on January 16, 1985 that the failure was attributed to a lack of fusion defect (about 40 degrees of arc) on the original weld of the pipe to the valve body. The leak may have developed from the elevated temperature the weld was exposed to during the Core Spray Overpressurization event or may have been totally unrelated. No further investigation is planned by plant management.

c. Intermediate Range Monitors (IRMs) inoperable - Unit 1

During a routine safety tour of the Unit 1 control room on January 18, 1985, the inspector observed that IRM Channel "A" was indicating about 25% scale on IRM range 3. The reactor was shutdown with the mode switch in the "Refuel" position. Reactor Pressure was about 700 psig. All other operable IRM Channels indicated between 15-25% scale on range 1. The erroneous high reading on IRM channel "A" was attributed to excessive noise possibly due to electrical "cross-talk" at containment penetrations. IRM Channels "B" and "C" were concurrently inoperable and bypassed. Since the IRM high flux scram on ranges 1 and 2 of Channel "A" was effectively bypassed by the range switch being maintained in the range 3 position, the inspector considered that the minimum number of operable instrument channels per trip system was not being maintained. (Channels "A", "C", "E" and "G" are in one trip system whereas Channels "B", "D", "F" and "H" are in the other trip system).

The inspector questioned the Shift Engineer and the Operations Supervisor regarding the applicability of TS 3.1, pointing out the following:

(1) TS Table 3.1.A requires that the IRM high flux scram be operable in the refuel mode.

(2) TS Table 3.1.A requires that a minimum of 3 IRM channels per trip system be operable in all reactor modes except the run mode in which case it is bypassed by the mode switch.

(3) Note 1 of TS Table 3.1.A states that, "there shall be two operable or tripped trip systems for each function."

(4) Note 22 of TS Table 3.1.A states that, "3 IRMs per trip system is not required in shutdown or refuel if at least 4 IRMs (one in each quadrant) have their shorting links removed to provide a non-coincidence high flux scram."

The inspector noted that neither a half scram had been inserted (to trip the inoperable trip system) nor had the IRM shorting links been removed; in addition, no other action had been taken to prevent rod movement. The Shift Engineer and Operations Supervisor initially indicated concurrence that one of two actions was required and began consultation to resolve the discrepancy. It was apparent that up until this point plant operations had not fully considered the ramifications of the recently inoperable IRM Channel. (Channel "C" had been inoperable for some time, and Channel "A" was declared inoperable at 2100 on January 17, 1985).

Discussions among plant personnel continued, and the reactor mode switch was placed in shutdown later that day. The Plant Manager was informed at the exit meeting on January 25, 1985 of this violation of

TS 3.1.A. (259/85-06-01). The cause of the excessive noise on Channel "A" and "C" is an open item to be followed up by the resident inspectors. (259/85-06-02).

During this exit meeting the Plant Manager took exception to the violation indicating that they considered note 1A of TS Table 3.1.A to be applicable with less than the minimum required IRM Channels. This note requires that the plant "initiate insertion of operable rods and complete insertion of all operable rods within four hours. In refueling mode, suspend all operations involving core alterations and fully insert all operable control rods within one hour".

The inspectors noted that this was an "after the fact" interpretation and that no decisive action was taken by plant operations until the concern was raised by the inspectors. No action had been taken by operations to prevent single rod movement in the "refuel mode" until noted by the inspector.

d. Standby Liquid Control Event - Unit 1

At 1140 on January 11, 1985, a Notification of Unusual Event was declared due to the Unit 1 SLC becoming inoperable. The SLC pump suction piping temperature was found to be low during a routine tour by the Unit 1 operators. While investigating the cause of the low temperature condition, the 1A SLC pump suction trace heater breaker was found in a tripped condition. Several attempts to shut the breaker resulted in subsequent breaker trips. The 1B SLC pump was concurrently inoperable due to its onsite diesel power source being out of service for routine inspection.

Technical Specification 3.4.D requires the unit be placed in a shutdown condition with all rods fully inserted within 24 hours if both SLC systems are inoperable. The 1A trace heater problem was traced to a failed 480/120 VAC transformer located in the breaker compartment. The transformer was replaced and the Unusual Event was cancelled at 1417 on January 11, 1985. The event was followed by the inspectors, and several concerns were noted to plant management.

1. While repairs were being made to the 1A trace heater circuit breaker the inspectors noted that pump suction temperatures were opposite from that expected by the existing conditions. The 1A suction piping was normal (about 80 degrees F.) whereas the 1B suction piping was low (about 70 degrees F.)

2. Only one spot was provided on the operator log sheet for recording SLC pump suction temperatures. Both A and B suction temperatures were recorded in the same spot with no provision for determining which temperature corresponds to the A or B piping. The log sheet was revised on January 15, 1985 to provide separate spaces for the A and B temperatures.

Operators initially suspected that a potential wiring or labeling error existed since the temperatures appeared reversed, and the 1B suction piping temperature increased after the 1A trace heater breaker was shut following transformer replacement. Power supplies and identification tags were checked on SLC pumps, circuit breakers and trace heaters, but no errors were found. During the evening shift on January 11, 1985, 1A SLC pump suction piping was found to be high (118 degrees F.), and a maintenance request was initiated to check the trace heater thermostats. The 1A thermostat was found to be set incorrectly (about 20 degrees F. above the normal setting). The thermostat was recalibrated, and both 1A and 1B SLC pump suction piping temperatures remained stable for the next several days. Further evaluation of the temperature inconsistencies prompted plant personnel to check the calibration of the red organic fluid-filled thermometers which were used to determine suction piping temperatures. Both thermometers were removed (without maintaining traceability), and one of the thermometers was found to read 16 degrees F. lower than actual. An apparent fluid separation had occurred. Plant personnel, after discussions with the manufacturer, attributed this separation problem to horizontal storage of the thermometers. Changes have been initiated to plant procedures to prevent horizontal storage of thermometers in the future.

The inspectors reviewed the plant's "Program to Establish and Maintain Certifiably Accurate Thermometers" (BF 17.19). This program was implemented in response to a previous violation (259, 260, 296/82-34-06) and requires power stores to obtain certification papers for all stocked thermometers attesting to their initial accuracy. Three recent thermometer procurements were reviewed. The following purchases neither required nor obtained the certifications required by BF 17.19:

1. Requisition No. 355667, dated July 19, 1984, for 12 red organic liquid, 0-230 deg F., self-indicating thermometers.

2. Requisition No. 351094, dated June 27, 1984, for 60 liquid in glass, (-20)-120 deg F., self-indicating thermometers.

3. Requisition No 934217, dated October 25, 1983, for 4 bimetallic, range 0-240 deg F., self-indicating thermometers.

This is a violation of 10 CFR 50, Appendix B, Criterion XVI, failure to correct conditions adverse to quality (259, 260, 296/85-06-03).

The failure of the 1A SLC pump suction trace heater transformer was initially attributed to random failure due to insulation breakdown. The inspectors questioned this since evidence of soot from charred insulation also existed on the Unit 1 1B breaker compartment. A maintenance history review was performed by electrical maintenance personnel back to 1982 (beginning of maintenance request (MR) tracking system at Browns Ferry). Two previous failures of the transformers in the 1A breaker compartment were found to have occurred in 1983 and 1984. A complete evaluation is now in progress by the electrical maintenance group. This item will remain open to review generic concerns. (259/85-06-04).

e. Natural Circulation Event on Unit 3

An operational transient occurred on Unit 3 during power operation on January 7, 1985. At 1420 the "B" recirculation motor-generator (MG) tripped due to high lube oil temperature (>210 degrees F.) causing a loss of the "B" recirculation pump and placing the unit in single loop operation. Similarly, at 1433 the "A" recirculation pump had been lost placing the unit in natural circulation.

Instrument Maintenance personnel (IM) were performing maintenance on a temperature transmitter to reactor feedwater line B (TT-3-50C located on panel 3-25-182 Dwg. 45N3635-3D) per a plant maintenance request (MR #157981). The IM had removed the instrument for maintenance and were reinstalling the instrument when they inadvertently allowed the power cable to short to ground. This occurred at approximately 1410. This caused a breaker supplying power to panel 25-182 (breaker 411 panel 9-9 cabinet 4) from the plant preferred bus to trip.

This should have caused an alarm in the control room (EA-57-96 on panel 9-8) to initiate but apparently did not. The IM returned to the shop to determine the power source for panel 25-182. At the time of the incident all of the instruments that were affected by loss of this power source was not known.

The instrument panels determined to be affected were:

3-25-179	Main generator exciter air temp controller and bus heat exchanger air temp controller.
3-25-180	Raw cooling water (RCW) to recirculation MG set "A" oil coolers.
3-25-181	RCW to recirculation MG set "B" oil coolers.
3-25-182	Electro-Hydraulic Control (EHC) fluid temp controller, turbine oil temp controller and reactor feedwater lines "A" and "B" temp transmitters (TT-3-48C and 50C, respectively).
3-25-184	RCW to reactor feed pump turbines (RFPT) "A", "B" and "C" oil coolers.
3-25-196	Reactor building closed cooling water (RBCCW) heat exchangers "A" and "B" temp controllers.

The loss of power to these panels caused the respective electrical to pneumatic (E/P) converters to give a false signal to the temperature controllers. This caused the RCW temperature control valves for RBCCW heat exchangers "A" and "B", the recirculation MG set "A" and "B" oil coolers, the EHC fluid coolers, the RFPT "A", "B" and "C" oil coolers and the generator exciter to go full closed. Therefore, all RCW to RBCCW and RCW to the recirculation MG sets was lost. This resulted in the trip of recirculation pumps and loss of RBCCW to the drywell air coolers. Drywell pressure increased to 1.5 psig.

At approximately 1418 the unit operator, after noting drywell pressure increasing and RBCCW temperature increasing, began venting the drywell in accordance with Operating Instruction (OI-64). The inspector will further investigate the practice of venting the drywell with an unknown transient in process. (Open Item 296/85-06-05).

At approximately 1420 the 3B recirculation MG set tripped on high oil temperature. The Unit 3 Assistant Shift Engineer (ASE) went to the recirculation pump MG set to determine the cause of the high temperature. He noted the RCW temperature control valves closed with air available and began opening the manual bypass valves on the coolers, but at approximately 1433 the 3A recirculation pump MG set tripped on high oil temperature. At this point the unit operator inserted control rods per the emergency rod insertion sheet. Initially power was 45%, and immediately after the recirculation pump trips control rods were inserted to reduce the margin to the Average Power Range Monitor (APRM) rod blocks. Rod insertions and the buildup of xenon resulted in a power decrease to 33%. The rod insertions, however, caused the "R" factor to be less than the value (1.0) as required by TS 3.5.L.1. ("R" factor is the ratio of fractional rated power (FRP) to core maximum fractional limiting power density (CMFLPD). Six hours are allowed to correct this condition, then power must be reduced to less than 25% within four hours. Also, the rod pattern did not meet that required by the Rod Worth Minimizer Sequence prior to reducing power below 30%. At approximately 1440 the IM reported to operations that they had tripped breaker 411, but no one connected the loss of that one breaker with the transient in progress. The Unit 3 ASE checked the RBCCW heat exchangers, found the temperature control valves closed and began opening the manual bypass valves, restoring drywell cooling. He noted air was available to the control valves. At that point operations personnel began looking for an electrical problem. Concurrently, the IM were investigating what loads were affected by the trip of breaker 411 on panel 9-9. Between 1445 and 1500 the Unit 1 ASE reset breaker 411, and all temperature controllers returned to normal. At approximately 1455 the unit 1 operator ceased venting the drywell when he noted drywell pressure had decreased to .5 psig due to venting and restoration of drywell cooling. At approximately 1515 IM reported their findings to the Unit 3 Shift Engineer, and the cause of the transient was determined.

Subsequently, the IM went to all six panels involved and verified proper operation of the controllers. The drywell to torus Delta Pressure was reestablished at 1520 after throttling back on drywell cooling water and allowing the drywell temperature to increase back to normal. The drywell to torus pressure differential is required to be maintained greater than 1.1 psid (TS 3.7.A.6.B).

By this time, the temperature difference between the dome and bottom head drain had exceeded the 145 degrees F. differential temperature limit relating to restart of the recirculation pumps (TS 3.6.A.7) (in fact at approximately 1445 the operators had determined the Delta Temperature (Delta T) to be 175 degrees F.). This prevented restart of the recirculation pumps. When it became apparent that this temperature difference could not be restored within limits of operating conditions and that manipulating the rod pattern to an acceptable sequence would be very difficult without recirculation pumps, the decision to manually scram the reactor was made. At 1730 Unit 3 was manually scrammed from 33% power and 15% flow. The reactor was depressurized until the dome/drain Delta T was restored to less than 145 degrees F., and the recirculation pumps were restarted.

Another item of concern to the resident inspectors occurred on January 13, 1985. With Unit 3 operating at full power, the dome/drain Delta T was determined to be 154 degrees F. (dome temperature 544 degrees F., bottom drain temperature 390 degrees F.). This was compared to Unit 1 which was also operating at full power. On Unit 1 the dome/drain Delta T was 60 degrees F. (dome temperature 545 degrees F., bottom drain temperature was 485 degrees F.). Since the Browns Ferry units operate at full power with only about 25 degrees of subcooling, it appears Unit 3's bottom drain temperature indication is 100 degrees F. too low. This item is being investigated by the licensee and will remain an open item for further inspector followup. (296/85-06-06).

Operation in natural circulation is allowed per TS 3.6.F.3 for 12 hours. Prior to restarting a recirculation pump the difference in temperature between the dome and bottom head drain must be within 145 degrees F. (TS 3.6.A.7). Discussions with operations personnel revealed that the pumps must be restarted within 20 minutes to meet this requirement on Unit 3.

f. Hydrogen/Oxygen Monitor Inoperable - Unit 1

At 1715 on January 13, 1985, while the operator was shifting sample location (Drywell/Torus) of the Division 1 Containment Atmosphere Monitoring System (CAMS), circuit breaker 224 on 120 volt Instrument and Control (I and C) Bus "A", Panel 9-9 tripped causing a loss of both Division I and II CAMS on Unit 1. The selector switch was returned to its original position and the circuit breaker was re-shut, restoring both divisions back to service at 1720. Operators determined that during the time both CAMS Divisions were inoperable, a 24-hour limiting condition of operation existed. The fault was later attributed to a grounded solenoid in the Division I torus hydrogen sample outboard isolation valve which caused breaker 224 to trip. The Division II Primary Containment Isolation Interlocks (also powered from breaker 224) then properly responded to close the Division II isolation valves causing a loss of both CAMS. During troubleshooting of the problem, plant maintenance personnel discovered a discrepancy between the cable tags and the solenoid valves which initially indicated that the torus oxygen sample inboard isolation valve had shorted to ground. A discrepancy report was issued to verify wiring of the entire system, as well as, the CAMS for Units 2 and 3. The wiring error had no effect on the overall system operability since all of the torus isolation valves connect to a common node.

g. High Pressure Coolant Injection (HPCI) Valve Problem - Unit 3

At 1100 on January 11, 1985, Unit 3 HPCI pump failed to reach the rated flow of 5000 gallons per minute (GPM) in less than 25 seconds as required by SI 4.5.E.1.d. and e., HPCI Turbine and Pump Flow Test, respectively. The time was found to be 35 seconds and HPCI was declared inoperable. Investigation by the licensee found that following reassembly after maintenance on a HPCI steam isolation valve, FCV 3-76-16, (LER 296/84014 dated 12/6/84) a limit switch which controls the starting of the HPCI auxiliary oil pump was set incorrectly such that the auxiliary oil pump started when the steam isolation was fully open versus just off the closed seat.

The motor-operated valve 73-16 normally takes 10-15 seconds to open, and the incorrect limit switch setting results in excessive time for the HPCI system to reach rated flow of 5000 GPM. The FSAR section 7.4.3.2.5, HPCI Valve Control, states HPCI should reach design flow rate within 25 seconds from the receipt of the initiation signal.

The incorrect setting occurred due to a drawing error (TVA Drawing 45N714-2) which stated the limit switch should close when the valve (73-16) is fully open. Review of Electrical Maintenance Instruction 18 (EMI-18), Limit and Torque Switch Setting on Motor Operated Valves, data sheets showed the setting was incorrectly performed on December 9, 1984.

Technical Specification 3.5.E.1 requires HPCI to be operable whenever there is irradiated fuel in the reactor vessel and pressure is greater than 122 psig. HPCI was inoperable during all periods of power operation from December 9, 1984 to January 12, 1985.

Additionally, two procedural errors were found in the plant surveillance instructions. The procedure for the pump flow test, SI 4.5.E.2.d. and e, using auxiliary steam from the plant's auxiliary boiler, does not check the requirement to reach rated flow in less than 25 seconds due to capacity limits on steam flow. The procedure using reactor steam, SI 4.5.E.1.d. and e, performs the timing test but this procedure was not used after the maintenance on December 9, 1984. Also, the procedure for reactor steam testing in a note after step 18 stated the time for the 25 seconds was between the start of the auxiliary oil pump and attainment of 5000 GPM flow. The note was incorrect in that the time required should have been from the initiation signal to the time required to reach rated flow, as stated in the system design analysis in FSAR section 7.4.

Unit 1 HPCI limit switches had previously been incorrectly set on June 24, 1984 and were reset on January 18, 1985. All previous flow tests using SI 4.5.E.1.d and e, were acceptable; however, it is inconclusive whether the Unit 1 HPCI was operable or not. Discussions with plant personnel revealed that although the procedure said to perform the timing from the start of the auxiliary oil, the procedure was not always followed due to the known discrepancy in the procedure. The 35-second timing problem was thus discovered by not following the surveillance procedure.

During the review it was noted that the EMI-18s as far back as July 1984, have not been reviewed by the cognizant engineer. A more timely review of these instructions may have helped to prevent the limit switch setting errors. The review delay was attributed to a backlog of work and difficulty of the review. Each time the limit switches are set the drawings must be checked to determine the proper setup. There is no procedure for the setup of an individual valve but only a generic procedure. The craftsmen must review the applicable drawings to determine the proper setup each time valve limit switches are adjusted.

Two violations were identified in this area and are summarized below:

1. TS 3.5.E.1(2) HPCI Inoperable Unit 3 (296/85-06-07).

2. 10 CFR 50 Appendix B, Criterion V (259/85-06-08).

   Example 1 - HPCI Drawing error 45N714-2
   Example 2 - SI 4.5.E.2.d and e (Auxiliary Steam) No timing test
   Example 3 - SI 4.5.E.1.d and e (Reactor Steam) Timing test wrong.

These items were discussed with the plant manager in an exit meeting on January 25, 1985.

h. Unusual Event Due to Inoperable Diesel Battery - Unit 1

At 1800 on January 9, 1985, while performing EMI-40 (Yearly Battery Connection Torque Check) on the 1A Diesel Generator Batteries, a loose connection was found which required that the operators declare the 1A Diesel Generator inoperable. The 1C Residual Heat Removal System (RHR) was concurrently inoperable in the containment cooling mode due to maintenance in progress on the "C" RHR Service Water Header. TS 3.9.B.3 requires an orderly shutdown to be initiated under this condition and that the reactor shall be in cold shutdown within 24 hours. At 2230 plant operators declared a Notification of Unusual Event in accordance with Browns Ferry Implementing Procedures. The Unusual Event was cancelled at 2335 on January 9, 1985, after the battery connection was repaired, and the 1A Diesel Generator was tested for operability. Although the Shift Engineer, Shift Technical Advisor, Electrical Maintenance Supervisor and a plant management representative temporarily assigned to shift work (known as the Monitor/Evaluator) were all involved in determining the appropriate actions, it was 2 hours after the loose connection was found prior to commencement of load reduction, and 4-1/2 hours before the Notification of Unusual Event was declared.

i. Scram due to Loss of Feedwater - Unit 1

At 1440 on January 16, 1985, Unit 1 scrammed from 99.7% power on low reactor water level. The cause was attributed to failure of the feedwater control circuits that supplies feedwater to the reactor during operation. On loss of feedwater, reactor water level decreased below the LO-LO level (-51.5") thus initiating the following safety functions: recirculation pumps tripped, main steam isolation valves (MSIV) shut, HPCI initiated and the reactor core isolation cooling (RCIC) initiated. The HPCI injected for 7 to 10 mins., until it tripped on high reactor water level (54"). The RCIC did not inject but tripped on turbine mechanical overspeed and high exhaust pressure. During the event two main steam relief valves (MSRVs) (1-22 and 1-23) were used manually for 15 secs. to control reactor pressure. The MSIVs were reopened after the primary containment isolation valves were reset. Subsequent investigation revealed the following information about this event:

1. RCIC failure to start:

The RCIC system was tested after the event to determine the cause of the high exhaust pressure and overspeed trip.

On January 17, 1985, Instrument Maintenance personnel investigated the problem by checking FIC-71-36A (RCIC controller). It was functionally checked, and no problem was found with the controller.

Surveillance Instruction 4.5.F.1.d and e (RCIC System Flow Test) was conducted to verify operation of RCIC. While adjusting FCV-71-38 (Step 15 of SI), the RCIC tripped. Annunciator PA-71-13 (RCIC turbine exhaust discharge pressure high) was received at the time of the trip. The turbine was restarted and again at Step 15 the turbine tripped with the same annunciator.

The pressure switches which trip the turbine and bring in the alarm (PS-71-13A and PS-71-13B) were checked and found to operate at the correct setpoint (25 psig plus water leg). The pressure indicator loop for exhaust discharge pressure was checked and found to operate correctly (No adjustments were made).

SI 4.5.F.1.d/e was conducted again and RCIC operated properly. RCIC was declared operable by Operations. Plant management has committed to run the RCIC operability surveillance after plant startup to assure system performance.

2. Feedwater Control Circuit and Failure of Main Steam Flow Recorder to function during scram:

On January 17, 1985, the master level controller, LIC 46-5, was visually inspected for burned or damaged components, but none were found. The system wiring was checked for nicks, cuts and bad solder joints, but none were found. The controller was installed in a test setup and was verified to function properly. The calibration of the controller was verified to be correct. Additionally, the controller was subjected to minor and severe vibration to try to get it to fail, but the controller continued to function properly. The steam flow and feedwater flow transmitters' calibration and operation were checked and verified to be functioning as designed. The total steam flow modifier and flow switch calibration was verified correct.

The controller was reinstalled in Unit 1 and checked in both single and three element control with "A" reactor feed pump (RFP) maintaining reactor level, while "B" and "C" control stations were operating in automatic simulating operating conditions. The controller was then subjected to a vibration test in an effort to recreate controller failure, but the controller continued to function properly.

The controller cabling was inspected for nicks, cuts and breaks, but no problem was found. All associated components were verified to be operating as designed. No cause was thus found for the loss of feedwater event. Startup testing will be performed on the system during the next reactor startup.

The total steam flow recorder did not show any change in the steam flow during the scram event. An investigation showed that the recorder amplifier had failed in FR-46-5. A failure investigation determined that capacitor C-8 shorted, due to end of life cycle. The life expectancy for electrolylic capacitors is addressed in Standard Practice 6.8. All electrolytic capacitors were checked in the circuit.

Several capacitors were checked and found out of tolerance, they were replaced as required by Standard Practice 6.8. This item may be a generic concern and should be further addressed in a Preventive Maintenance System (PMS) program. This item will be left open and reviewed at a later date. (259/85-06-09).

3. Acoustic Monitor for Main Steam Relief Valve (MSRV) 1-23 failed:

During the event the operator opened MSRV 1-23 to control reactor pressure. Upon reshutting the valve the acoustic monitor still indicated the valve was open. Investigation into the cause of the failure is inconclusive. The acoustic monitor circuit was tested at the encouragement of the resident. No problem was found with the circuit configuration from the sensing accelerometer to the control room alarm. Instrument personnel indicated that this problem has occurred in the past, and this may be a generic problem. If this is not a generic-type problem, then it could only be concluded the MSRV stuck open. The operator cycled the MSRV several times to get it shut. Upon resetting the acoustic monitor circuit the alarm cleared. This item will be left open for licensee followup. (259/85-06-10).

The residents' investigation of this event was inconclusive in determining whether or not the MSRV stuck open. The licensee concluded the MSRV did not stick open.

4. Recirculation Pump Failed to Start After Event:

While recovering from the scram, 1A recirculation pump failed to start. This item is being left open for inspector followup. (259/85-06-11).

5. Event Summary:

In summary it can be concluded that no cause for the scram could be determined. Investigation continues in several areas as indicated above.

J. Shutdown Due to Unidentified Leakage - Unit 1

During a Unit 1 startup on January 21, 1985 an unusual event was declared at 1916 due to an unidentified leak in the drywell of 28 GPM. A shutdown was initiated, and a drywell entry made to locate the leakage. The source of the leakage was due to a temporary hose which had inadvertently been left in place during the short outage prior to startup. The hose was connected around core spray testable check valve 73-26 to equalize pressure around the check valve in performance of SI 3.2.2. The 300 lb. rated hose blew off a fitting at an estimated plant pressure of 800 lbs. The leakage was isolated by shutting four valves in the three/quarter inch test lines. Two workers received minor skin contamination when their rubber suits tore in the drywell. Both were decontaminated and returned to duty. Another leak was found during inspection of the drywell on the vent line-to-bonnet weld on a recirculation pump discharge valve (68-3).

Valve 73-26 was inoperable due to the installation of the test hose which bypassed and equalized pressure around the testable check valve. In an exit meeting with the plant manager on January 25, 1985, this was noted as a violation of TS 3.7.D.1 which requires all isolation valves listed in TS Table 3.7.A to be operable during reactor power operation (259/85-06-12).

A review of SI 3.2.2, MOV Cycled During Cold Shutdown, performed on Unit 1 from January 18, 1985 to January 21, 1985, revealed several problems. Attachment A, Test Methods - Testable Check Valves, was the procedure used to cycle core spray testable check valve 73-26. This procedure was inadequate and contained no steps or signoff steps to install or remove the bypass hose used to equalize pressure around the valve or for repositioning of the valves to which the hose was connected. The inadequate procedure was given as the fourth example of the 10 CFR 50, Appendix B, Criterion V Violation. (259, 260, 296/85-06-08). This violation was discussed with the plant manager in the exit meeting on January 25, 1985.

The completed SI 3.2.2 indicated test method one (cycle valve with actuator from the control room) was used to test the check valve 73-26. Method three gave the instruction for equalizing pressure using the temporary hose. Discussion with the plant manager indicated the operator in the control room had been unaware a bypass hose was connected around the valve 73-26. The maintenance workers which installed the hose did not use the SI but used a maintenance request form to perform work on the valve. Failure to follow procedure was given as the fifth example of the violation of 10 CFR 50, Appendix B, Criterion V. (259, 260, 296/85-06-08).

Additionally, discussions with plant personnel revealed hoses were installed around the high pressure coolant injection system, reactor core isolation cooling system and residual heat removal system check valves, but the method as shown on the completed SI did not indicate the hose method was used. This SI was noted as completed in the Unit 1 Operator's Log at 0015 on January 21, 1985.

The cover sheet of the SI contains a block to indicate whether any delays were experienced during performance of the SI, and none were indicated. However, initially valve 73-26 would not operate using the actuator, and thus the bypass hose was connected. The solenoid valve directing flow to the air actuator was disassembled, and the solenoid valve body taken from Unit 2 to install in Unit 1. The valve body was found not to be interchangeable with the valve body from Unit 1. The solenoid was then taken from Unit 2 so a workable assembly could be made. The licensee plans to investigate why the parts were not interchangeable, and why the solenoid valve would not function.

The same check valve solenoid and actuator had previously been incorrectly assembled such that the actuator held the testable check valve in the open condition and was a contributing factor to the core spray loop piping over-pressurization event on August 14, 1984. This will remain an open item until the licensee completes its evaluation. (259/85-06-13).

6. Maintenance Observation (62703)

Plant maintenance activities of selected safety-related systems and components were observed/reviewed to ascertain that they were conducted in accordance with requirements. The following items were considered during this review: the limiting conditions for operations were met; activities were accomplished using approved procedures; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; proper tagout clearance procedures were adhered to; Technical Specification adherence; and radiological controls were implemented as required.

Maintenance requests were reviewed to determine 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 below listed maintenance activities during this report period:

a. Installation of the Standby Liquid Control heat trace power supply transformer.

b. EMI-18, Limit and Torque Switch Adjustment for Critical Safety Systems and Components (CSSC) Motor Operated Valves.

c. Browns Ferry Standard Practice 6.8, Aluminum Electrolytic Capacitors.

d. Mechanical Maintenance Instruction MMI-87, Inspection and Maintenance of Limitorque Operators.

The details of the observations are included in paragraph five.

7. Surveillance Testing Observation (61726)

The inspectors observed and/or reviewed the below listed surveillance procedures. The inspection consisted of a review of the procedures for technical adequacy, conformance to Technical Specifications, verification of test instrument calibration, observation on the conduct of the test, removal from service and return to service of the system, a review of test data, limiting conditions for operation met, testing accomplished by qualified personnel and that the surveillance was completed at the required frequency.

a. SI 4.5.E.1.d and e, High Pressure Coolant Injection Turbine and Pump Flow Test (Reactor Steam).

b. SI 4.5.E.2.d and e, High Pressure Coolant Injection Turbine and Pump Flow Test (Auxiliary Steam).

c. SI 3.2.2, MOV Cycling During Cold Shutdown.

d. Technical Instruction 74, Post Trip Review.

The details of the observations are included in paragraph five.

8. Reportable Occurrences (90712, 92700)

The below listed licensee event reports (LERs) were reviewed to determine if the information provided met NRC requirements. The determination included: adequacy of event description, verification of compliance with TS and regulatory requirements, corrective action taken, existence of potential generic problems, reporting requirements satisfied and the relative safety significance of each event. Additional in-plant reviews and discussion with plant personnel, as appropriate, were conducted for those reports indicated by an asterisk. The following LERs are closed:

LER No.	Date	Event
*296/84-01R1	1/3/84	Inadequate cooling to diesel generators due to flow blockage in EECW system
*296/84-12	11/20/84	Manual Reactor scram due to vessel low water level concerns
*296/84-14	12/06/84	HPCI turbine steam isolation valve leakage and pinion gear parts missing
*296/84-15	12/09/84	Unit 3 manual scram due to a lost of condensate pump 3A

No violations or deviations were identified.

9. Reactor Trips (93702)

The inspectors reviewed activities associated with the below listed reactor trips during this report period. The review included determination of cause, safety significance, performance of personnel and systems and corrective action. The inspectors examined instrument recordings, computer printouts, operations journal entries and scram reports, and they had discussions with operations, maintenance and engineering support personnel as appropriate.

Unit 3 scrammed at 1152 on November 20, 1984 from 4.5% power during startup while establishing conditions necessary to perform SI 4.6.D (Relief Valve Functional Test). About one and one-half bypass valves (out of 10 valves) were opened and reactor water level began decreasing. Attempts to place additional condensate booster pumps in service to increase reactor feedwater flow were unsuccessful, since their local controllers were in the "SAFE/STOP" position thus preventing startup from the control room. The reactor was manually scrammed when reactor water level decreased below the scram setpoint. An investigation was conducted to determine if Technical Specification safety limits (TS 1.1.B) had been exceeded, since an automatic scram had not occurred at a reactor water level of 11 inches (Scram Barton trip level) as indicated in the control room. Results of the study indicated that at lower than normal operating pressure, actual water level differs from indicated water level due to temperature compensation of the reference leg and that actual water level was 12.0 inches which is in excess of the + 10 inches required by Technical Specifications. No safety limits were exceeded. All safety systems functioned properly during the transient.

The following items were noted as an open item (259/85-06-14). These items are currently being corrected by plant management:

a. TI 74, Scram Discharge Instrument Volume fill time performance evaluation data sheet 74.2 was not maintained as a controlled document. The completed data sheets were being maintained only in a cognizant engineer's notebook.

b. Computer data points for the TI 74 data sheets are incorrectly referenced.

c. TI 74, "Post Trip Review and Analysis" requires the recording of scram discharge volume fill times. The procedure contained no acceptance criteria other than the comment that, "fill time is dependent upon Control Rod Drive (CRD) rod positions at the time of the scram and on leakage past the CRD seals".

10. Regulatory Performance Improvement Program (RPIP)

The responsible section chief reviewed the status of RPIP and actions taken by TVA to implement specific items as required by NRC Confirmatory Order EA 84-34 dated July 13, 1984. TVA has assigned a senior manager as RPIP Coordinator at the site. His responsibilities include verifying that each task has been implemented as described, has met objectives and that the necessary programs are in place to insure that objectives will continue to be met. Most of the short term items have been indicated as complete, but they have not been signed off as completed by the RPIP Coordinator. Based on the above review, the following item was closed:

Short Term Item

1.1

(84-SC-01) SC=Section Chief	Ensure that each manager understands his/her responsibility and authority regarding compliance.