UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

January 28, 2005

Tennessee Valley Authority
ATTN.: Mr. K. W. Singer
Chief Nuclear Officer and
Executive Vice President
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000260/2004005, 05000296/2004005

Dear Mr. Singer:

On December 31, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your operating Browns Ferry Unit 2 and 3 reactor facilities. The enclosed integrated quarterly inspection report documents the inspection results, which were discussed on January 18, 2005, with Mr. M. Skaggs, Mr. K. Krueger, and other members of your staff. Results from our inspection of your Unit 1 Recovery Project are documented in a separate Unit 1 integrated inspection report.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one NRC identified finding and three self-revealing findings of very low safety significance (Green) which were determined to involve violations of NRC requirements. However, because of the very low safety significance and because the findings were entered into your corrective action program, the NRC is treating the findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any non-cited violation in the enclosed report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Browns Ferry Nuclear Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Stephen J. Cahill, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket Nos. 50-260, 50-296
License Nos. DPR-52, DPR-68

Enclosure: Inspection Report 05000260/2004005 AND 05000296/2004005
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION REGION II

Docket Nos:	50-260, 50-296
License Nos:	DPR-52, DPR-68
Report No:	05000260/2004-005, 05000296/2004-005
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Units 2 & 3
Location:	Corner of Shaw and Nuclear Plant Roads Athens, AL 35611
Dates:	September 26, 2004 - December 31, 2004
Inspectors:	B. Holbrook, Senior Resident Inspector R. Monk, Resident Inspector E. Christnot, Resident Inspector Gerry Laska, Senior Operations Examiner (Section 1R11.2) Tim Kolb, Operations Examiner (Section 1R11.2)
Approved by:	Stephen J. Cahill, Chief Reactor Project Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000260/2004-005, 05000296/2004-005; 9/26/2004 - 12/31/2004; Browns Ferry Nuclear Plant, Units 2 and 3; Permanent Plant Modifications; Surveillance Testing

The report covered approximately a three-month period of routine inspection by resident inspectors and regional licensing examiners. One inspector-identified non-cited violation (NCV) and three Green self-revealing NCVs were identified. The significance of issues is indicated by the color assigned (Green, White, Yellow, Red) using the Significance Determination Process in Inspection Manual Chapter 0609, Significance Determination Process (SDP). The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, Reactor Oversight Process, Revision 3, dated July 2000.

A. Inspector Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified an NCV of 10 CFR 50.65 (Maintenance Rule) for failing to demonstrate that the performance of the Reactor Motor-Operated Valve (RMOV) Board 1B was being effectively controlled through the performance of appropriate preventive maintenance such that the system remained capable of performing its intended function. As a result, after it exceeded its Maintenance Rule a(2) performance criteria, the licensee had not established goals nor monitored the performance of the RMOV Board 1B per 10 CFR 50.65a(1).

  This finding is more than minor because it affected the reliability objective of the Equipment Performance attribute under the Mitigating Systems Cornerstone. The finding is of very low safety significance because there was no design deficiency, the equipment affected by the board failure either failed in a safe manner or had its redundant equipment functional. (Section 1R12)

Cornerstone: Initiating Events

- Green. A self-revealing NCV was identified for the licensee's failure to comply with 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures and Drawings. As a result of inadequate procedures and poor human performance, a Reactor Building crane trolley was dropped approximately four feet onto the refuel floor while being rigged.

  This finding is greater than minor because it is associated with program and process attributes and affected the objective of the Reactor Safety/Initiating Event Cornerstone to limit the likelihood of those events that upset plant stability and challenge critical safety functions during at power operations. In addition, if left uncorrected, this finding would result in a more significant safety concern. This finding was determined to be a finding of very low safety significance because no initiating event or transient actually occurred, there was no permanent structural damage to the refuel floor, there was no functional degradation, and mitigating capability was not affected. The cause of the finding is related to the cross-cutting element of human performance. (Section 1R17)

- Green. A self-revealing NCV was identified for the licensee's failure, due to human performance, to comply with Technical Specification (TS) 5.4.1, Procedures, and correctly implement a surveillance test procedure for the Unit 2 Low Pressure Coolant Injection system. As a result, an inadvertent start of the Residual Heat Removal Pump 2B occurred.

  This finding is greater than minor because it is associated with program and process attributes and affected the objective of the Reactor Safety/Initiating Event Cornerstone to limit the likelihood of those events that upset plant stability and challenge critical safety functions during at-power operations. In addition, if left uncorrected, this finding would result in a more significant safety concern if it occurred on a more sensitive plant-critical component. This finding was evaluated using the SDP and was determined to be a finding of very low safety significance because there was no actual loss of safety function, all aspects of the Emergency Core Cooling Systems (ECCS) remained fully functional, and other redundant ECCS were available to fulfill their safety function. The cause of the finding is related to the cross-cutting element of human performance. (Section 1R22.1)

- Green. A self-revealing NCV was identified for the licensee's failure to comply with Unit 2 Technical Specification (TS) 5.4.1, Procedures. A human performance error in the failure to correctly implement a surveillance test procedure during relay calibration resulted in the loss of power to the safety-related 480-volt shutdown board 2A. As a result, multiple Technical Specification Limiting Conditions of Operation were entered. This event initiated Engineered Safety Features and caused the loss of systems important to safety on all three units.

  This finding is greater than minor because it is associated with program and process attributes and affected the objective of the Reactor Safety/Initiating Event Cornerstone to limit the likelihood of those events that upset plant stability and challenge critical safety functions during at-power operations. This finding was evaluated using the SDP and was determined to be a finding of very low safety significance because the event was of short duration (approximately six minutes), other redundant safety features were available and remained fully functional, and there was no loss of safety function. The cause of the finding is related to the cross-cutting element of human performance. (Section 1R22.2)

Licensee Identified Findings

NONE

Report Details

Summary of Plant Status

On October 24, 2004, Unit 2 decreased power to approximately 81% Rated Thermal Power (RTP) to repair a leaking discharge valve on Reactor Feedwater Pump 2C. Power was returned to 100% RTP on the same day. Power was reduced to about 79% RTP on November 25 due to a malfunction of the level control circuit of the 2C1 feedwater heater. Repairs were completed and power was returned to 100% RTP later the same day. Unit power remained at approximately 100% RTP during the remainder of the inspection period except for routine scheduled maintenance and testing.

On November 17, 2004, Unit 3 power was reduced to 65% RTP to conduct testing and complete maintenance to repair leaks, adjust leaking valve packing, and adjust control rod scram times and post-maintenance testing. Power was returned to 100% RTP on November 19. The unit automatically scrammed from 100% RTP on November 23 due to a loss of turbine/generator speed following a faulted distribution line. Unit restart began November 24 and was returned to 100% RTP on November 28. Unit power remained at approximately 100% RTP during the remainder of the inspection period except for routine scheduled maintenance and testing.

2. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection

.1 Weather Preparations

a. Inspection Scope

The inspectors reviewed licensee procedure 0-GOI-200-1, Freeze Protection Inspection, and reviewed licensee actions to implement the procedure in preparation for cold weather conditions. The inspectors reviewed open Problem Evaluation Reports (PERs) to verify that the licensee was identifying and correcting potential problems related to cold weather operations. The inspectors specifically reviewed PERs associated with incomplete work activities that were identified during cold weather preventative maintenance activities. The inspectors reviewed immediate and planned corrective actions to verify that they were appropriate. In addition, the inspectors reviewed procedure requirements and walked down selected areas of the plant to verify that systems and components were properly aligned as specified by the procedure. The inspectors discussed cold weather conditions with operations personnel to assess plant equipment conditions and personnel sensitivity to upcoming cold weather conditions. The inspectors conducted a walkdown tour of the main control rooms to assess system performance and alarm conditions of systems susceptible to cold weather conditions. In addition, the inspectors reviewed licensee procedure EPI-0-000-FRZ001,2,3, to verify that maintenance work, inspection, and testing of cold weather-related equipment was being performed as described in the procedure and that deficiencies were being documented as required by the procedure.

c. Findings

No findings of significance were identified.

.2 Actual Weather Conditions:

a. Inspection Scope

The inspectors reviewed licensee actions for an actual tornado warning for Limestone County and the site area that occurred on October 18. The inspectors reviewed licensee procedure 0-AOI-100-7, Tornado, to verify that actions taken were in accordance with the procedure. The inspectors also verified that, following the termination of the tornado warning, equipment was restored as specified by the procedure.

In addition, the inspectors toured the plant and control rooms early on the morning of December 20, when the outside temperature was approximately 15 degrees Fahrenheit (EF) to assess plant conditions for cold weather and determine if cold weather preparations were effective.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (Partial Walkdown)

a. Inspection Scope

The inspectors performed partial walkdowns of the three safety systems listed below to verify redundant or diverse train operability, as required by the plant Technical Specifications (TSs), while the other train of the system was out of service. In some cases, the system was selected because it would have been considered an unacceptable combination from a Probabilistic Safety Assessment (PSA) perspective for the equipment to be inoperable while another train or system was out of service. The inspectors' walkdowns were to verify that selected breaker, valve position, and support equipments were in the correct position for support system operation. The walkdown was also done to identify any discrepancies that impacted the function of the system or could lead to increased risk.

The inspectors reviewed procedures and system alignments to identify and resolve equipment problems that could cause initiating events or impact the availability and functional capability of mitigating systems or barriers. The inspectors' observations of equipment and component alignment for the partial walkdowns were compared to the alignment specified in system procedures included in the Attachment.

- Unit 2 Core Spray System Loop I while Loop II was in a test configuration
- The 4-kV distribution system for Unit 1 and Unit 2 during the replacement of the Unit 1 main transformers, 1A, 1B, and 1C.
- The 480-VAC safety-related distribution system prior to work to replace transformer TS1B

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors reviewed licensee procedures, SPP-10.10, Control of Transient Combustibles, and SPP-10.9, Control of Fire Protection Impairments, and conducted a walkdown of the ten fire areas listed below to verify a selected sample of the following: licensee control of transient combustibles and ignition sources; the material condition of fire equipment and fire barriers; operational lineup; and operational condition of selected components. Also, the inspectors verified that the selected fire protection impairments were identified and controlled in accordance with procedure SPP-10.9. In addition, the inspectors reviewed the Site Fire Hazards Analysis and applicable Pre-fire Plan drawings to verify that the necessary fire fighting equipment, such as fire extinguishers, hose stations, ladders, and communications equipment were in place. The inspectors reviewed a sampling of fire protection-related PERs to verify that the licensee was identifying and correcting fire protection problems. Pre-fire Plan drawings and documents reviewed are included in the Attachment.

- Fire Area 16, Units 2 and 3 Control Building
- Fire Area 14, Unit 3 480-V Shutdown Board Room (SDBR) A
- Fire Area 15, Unit 3 480-V SDBR B
- Fire Zone 2-3, Unit 2 RB EL 593 North of Line Q and Heat Exchanger (Hx) Rooms
- Fire Area 9, Unit 2 4-kV SDBR C
- Fire Area 18, Unit 2 Battery and Battery Board Room
- Fire Area 20, Unit1/2 Emergency Diesel Generator Building
- Fire Zone 2-4, Unit 2 RB EL 593 South of Line Q and Residual Heat Removal (RHR) HX Rooms
- Fire Area 1, Unit 1 RB: RHR Quad/HXs; Standby Liquid Control Tank Room; Fuel Pool Cooling Pumps
- Fire Zone 2-2, Unit 2 Reactor Building elevation 519-565 East of Line R11

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Resident Inspector Quarterly Review of Testing and/or Training Activities

a. Inspection Scope

The inspectors observed an operating crew's performance during a training session on October 4. The scenario included malfunctions related to risk- and safety-significant equipment and components for mitigating systems, electrical power. Operators were required to implement alarm, system operating, abnormal, and emergency operating instructions. The inspectors reviewed licensee procedures TRN-11.4, Continuing Training for Licensed Personnel; TRN-11.9, Simulator Exercise Guide Development and Revision; and OPDP-1, Conduct of Operations, to verify that the conduct of training, the formality of communication, procedure usage, alarm response, and control board manipulations were in accordance with the referenced procedures. The inspectors compared actions contained in the scenarios to operations procedures to verify that they matched. The inspectors also assessed instructor interface and control of the examination process as well as the level of detail and content of the post-scenario critiques. The specific scenario observed included the following:

- OPL173S106, Feedwater Line Break, HPCI Steam Line Break with Automatic Isolation Failure, Loss of High Pressure Makeup, Emergency Depressurization with Rods Out.

b. Findings

No findings of significance were identified.

.2 Licensed Operator Requalification Biennial Review

a. Inspection Scope

The inspectors reviewed documentation, interviewed licensee personnel, and observed the administration of simulator operating tests and Job Performance Measures (JPMs) associated with the licensee's operator requalification program. Each of the activities performed by the inspectors was done to assess the effectiveness of the licensee in implementing requalification requirements identified in 10 CFR 55, Operators' Licenses. Evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines established in NUREG-1021, Operator Licensing Examination Standards for Power Reactors, and Inspection Procedure 71111.11, Licensed Operator Requalification Program. The inspectors also reviewed and evaluated the licensee's simulation facility for adequacy for use in operator licensing examinations. The inspectors observed two crews during the performance of the operating tests. Documentation reviewed included written examinations, JPMs, simulator scenarios, licensee procedures, on-shift records, licensed operator qualification records, watchstanding and medical records, simulator modification request records and performance test records, the feedback process, and remediation plans. The records were inspected against the criteria listed in Inspection Procedure 71111.11. Documents reviewed during the inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the two samples listed below for items such as: (1) appropriate work practices; (2) identifying and addressing common cause failures; (3) scoping in accordance with 10 CFR 50.65(b) of the maintenance rule (MR); (4) characterizing reliability issues for performance; (5) trending key parameters for condition monitoring; (6) charging unavailability for performance; (7) classification and reclassification in accordance with 10 CFR 50.65(a)(1) or (a)(2); and (8) appropriateness of performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSCs/functions classified as (a)(1). In addition, the inspectors specifically reviewed events where ineffective equipment maintenance has resulted in invalid automatic actuations of Engineered Safeguards Systems affecting the operating units. Documents reviewed are listed in the Attachment. Items reviewed included the following:

- Snubber Failures and Maintenance. The failures were documented as part of the licensee’s corrective action program in the following PERs: 69448, 47817, 44427, 47623, 41692, 48020, 61924, 71278, 44318, 44457

- Safety-Related Breaker Performance

b. Findings

Introduction: A Green inspector-identified NCV of 10 CFR 50.65, Requirements for monitoring the effectiveness of maintenance at nuclear power plants, was identified for the licensee’s failure to demonstrate that the performance or condition of Reactor Motor-Operated Valve (RMOV) Board 1B was effectively controlled through appropriate preventative maintenance. As a result, the licensee did not establish goals or monitor the performance of the board per 10 CFR 50.65a(1) to ensure that appropriate corrective actions were initiated.

Description: The inspectors reviewed PER and WO records related to the loss of the safety-related breakers. The inspectors noted that the feeder breaker for RMOV board 1B had de-energized three times between August 26, 2003 and June 23, 2004. In each case, a load was being started but the individual load breaker did not trip open. In a typical selective trip design, the load breaker should trip open and not affect the feeder breaker to the board. The loads involved were the Unit 1 Reactor Protection System Bus (RPS) MG set B motor, the Control Bay Supply Fan motor 1B and RHRSW sump pump B motor in pump compartment C, respectively. (See additional details on this load in Section 4OA2). When this board trips, Reactor Protection System 1B de-energizes and the Standby Gas Treatment and Control Room Emergency Ventilation systems receive an automatic start signal. Plant operators on the operating units are required to respond to the annunciators associated with the unexpected start of these systems, assess plant conditions, and then realign the systems back to their normal standby configuration. Though some WO's were initiated and some breaker subcomponents were replaced, and the board's normal feeder breaker and alternate feeder breaker have been exchanged, no cause has yet been determined. At the conclusion of this inspection, there were outstanding work orders dating back to April of 2004. This board primarily affects systems on the non-operating Unit 1. However, the RHRSW sump pump B is common plant equipment, is safety-related, and is designed to protect other safety related common equipment. In addition, common Engineered Safety Feature equipment automatically starts in response to these equipment problems.

The inspectors reviewed licensee procedure 0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting-10 CFR 50.65, and noted that the functional failure criteria for this system is the loss of a 480-V board for more than five minutes. The performance criteria is no more than one functional failure per Unit in a 24-month rolling period. The inspectors' review of the operating logs indicated that the board was de-energized on April 22, at 14:06 and was re-energized at 15:00 for a total of 54 minutes and on June 23, the board was de-energized at 09:00 and re-energized at 10:00, for a total of 60 minutes. These two functional failures placed the board (System 268) in the 10 CFR 50.65(a)(1) category for not meeting the performance criteria. However, the licensee had not accounted for these functional failures and out-of-service times or identified that the board (system 268) had not met their performance criteria. The licensee had not established any additional performance monitoring goals or identified specific corrective actions.

Analysis: The inspectors determined that the licensee's failure to demonstrate that the performance or condition of the RMOV Board 1B was capable of achieving its specified reliability criteria was more than minor because it affected the reliability objective of the Equipment Performance attribute under the Mitigating Systems Cornerstone. The inspectors assessed the finding using the SDP and determined the finding to be of very low safety significance. The finding was of low safety significance because there was no design deficiency and the equipment affected by the board failure either failed in a safe manner or had its redundant equipment functional.

Enforcement: 10 CFR 50.65, Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Paragraph (a)(2) states, "Monitoring as specified in paragraph (a)(1) of this section is not required where it has been demonstrated that the performance or condition of a structure, system, or component is being effectively controlled through the performance of appropriate preventive maintenance, such that the structure, system, or component remains capable of performing its intended function." Paragraph (a)(1) states, in part, that the licensee "...shall monitor the performance or condition of structures, systems, or components, against licensee-established goals, in a manner sufficient to provide reasonable assurance that such structures, systems, and components...are capable of fulfilling their intended functions." Contrary to the above, prior to June 23, 2004, the licensee failed to demonstrate that the performance or condition of RMOV Board 1B was being effectively controlled through the performance of appropriate preventive maintenance such that the system remained capable of performing its intended function. Therefore, between June 23, 2004, and December 30, 2004, the licensee failed to establish goals and monitor RMOV Board 1B under paragraph a(1) or demonstrate that monitoring under a(1) was not required. The failure is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 05000259,260,296/2004005-01: Failure to Demonstrate that the RMOV Board 1B Performance Was Effectively Controlled per 10 CFR 50.65 (a)(2). This issue is in the licensee's Corrective Action Program as PER 74450.

1R13 Maintenance Risk Assessments and Emergent Work Control

d. Inspection Scope

For the six risk and emergent work assessments listed below, the inspectors reviewed licensee actions taken to plan and control the work activities to effectively manage and minimize risk. The inspectors verified that risk assessments were being performed as required by 10 CFR 50.65(a)(4). The inspectors reviewed: licensee procedure SPP-6.1, Work Order Process Initiation; SPP-7.1, Work Control Process; and 0-TI-367, BFN Dual Unit Maintenance, to verify that procedure steps and required actions were met. Also, the inspectors evaluated the adequacy of the licensee's risk assessments and the implementation of compensatory measures. The reviews completed included the following:

- Work Week 2228, two conditions required unique risk evaluations for Standby Liquid Control and Standby Gas Treatment work activities that resulted in two separate conditions where the risk was elevated to Orange (Scheduled)
- Unit 2 RCIC inoperable due to inability to verify system vented per 2-SR-3.5.1.1(RCIC) (Emergent)
- Bearing replacement on 2EN LPCI MG Set for high vibration (Emergent)
- Units 1 and 2: 4-kV distribution system during the replacement of the 1A, 1B, and 1C Unit 1 main transformers in accordance with DCN 51470 (Scheduled)
- Work Week 2450, conditions where risk was elevated (Yellow) for key safety functions of low pressure injection and electrical power (Scheduled)

- Work Week 2452, conditions where risk was elevated (Orange) for reactivity control and (Yellow) for electrical power (Scheduled)

b. Findings

No findings of significance were identified

1R14 Operator Performance During Non-Routine Evolutions and Events

The activities surrounding the Unit 3 Scram of November 23, 2004, are addressed in Section 4OA3.1 of this report.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following six operability evaluations to verify the technical adequacy of the evaluation and ensure that the licensee had adequately assessed TS operability. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) to verify that the system or component remained available to perform its intended function. In addition, the inspectors reviewed compensatory measures to verify that the measures worked as stated and the measures were adequately controlled. Where applicable, the inspectors reviewed licensee procedure SPP-3.1, Corrective Action Program, Appendix D, Guidelines for Degraded/Non-conforming Condition Evaluation and Resolution of Degraded/Non-conforming Conditions, to ensure that the licensee's evaluation met procedure requirements. The inspectors also reviewed a sampling of PERs to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

- Technical Specification out-of-tolerance condition for RCIC steam line pressure switch 2-PS-071-0001C
- Review of Common Cause Failure Analysis for Emergency Diesel Generator C, Procedure 0-TI-403
- High vibration levels on 0-MTR-031-2101 and 0-MTR-031-2201, A and B Control Bay Chiller chilled water circulating motors, respectively
- Review of Functional Evaluation following reactor building crane trolley drop accident, PER 40775
- Review of Functional Evaluation for PER 70848, seized diesel generator fuel injectors
- Review of Engineering Evaluation of Unit 3 core spray leak detection circuit and instrumentation following indication fluctuation

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (OWAs) and Cumulative Affect Review

a. Inspection Scope

The inspectors reviewed three OWAs to determine if the functional capability of the affected systems or operator reliability in responding to an initiating event was affected. The review was to evaluate the effect of the OWA on the operators' ability to implement abnormal or emergency operating procedures during transient or event conditions.

The inspectors conducted a detailed review of the selected OWA's to assess the cumulative effect of operator response during transients or events and to verify that procedure requirements were met for increased attention to the need for possible repair. The review included one OWA that was identified as the highest level priority (Level 1). The remaining were at a Level 2 or 3 priority. The inspectors also verified that the OWAs had been reviewed in accordance with site procedures and that work orders had been developed and scheduled for repair. The inspectors compared their observations and licensee actions to the requirements of Operations Directive Manual 4.11, Operator Work Around Program, and TVAN Standard Department Procedure OPDP-1, Conduct of Operations.

- Unit 1: 1-064-OWA-2004-0117, (Level 1 priority), this OWA had a potential affect on the common secondary containment while supplying air for Unit 1 torus work
- Unit 2: 2-002-OWA-2004-0118, (Level 2 priority), 2H condensate demineralizer valve slow to respond, WO 04-711282-000
- Unit Common: 0-077-OWA-2004-0093, (Level 3 priority), Standby Gas Treatment System Sump Low Level, WO 04-721966-000

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed licensee procedures 0-TI-405, Plant Modifications and Design Change Control, and SPP-9.3, Plant Modifications and Engineering Change Control, and observed part of the licensee's activities to implement a design change, that affected all units, while the units were online. The inspectors reviewed the associated 10 CFR 50.59 screening against the system design bases documentation to verify that the modifications had not affected system operability/availability. The inspectors reviewed selected ongoing and completed work activities to verify that installation was consistent with the design control documents. Design Change Notice (DCN) 60600, Upgrade the Common Reactor Building 125-Ton Bridge Crane, was reviewed.

b. Findings

Introduction: A Green self-revealing NCV was identified for the Failure to Comply with 10 CFR 50 Appendix B, Criterion V, Instructions, Procedures and Drawings. As a result of an inadequate procedure and poor human performance, a Reactor Building crane trolley drop occurred.

Description: On October 24, licensee and contract personnel were conducting work using WO 04-716728-000, the implementing work document, for Design Change Notice (DCN) 60600 to upgrade the common Reactor Building 125-ton bridge crane. Part of the DCN was to replace the 65000-pound trolley with a new one. During the rigging process to remove and lower the old trolley from the overhead to the Unit 1 refueling floor, one synthetic sling failed and one end of the trolley dropped approximately four feet to the concrete floor. The force associated with the drop resulted in the failure of one of the two remaining slings on the other end of the trolley. Operations and engineering personnel immediately performed a series of detailed inspections and determined that no plant operability or safety issue resulted. The licensee determined that the event did not challenge the safe operation of Units 2 and 3 or cause entry into any Limiting Conditions of Operation. The drop resulted in surface cracking and spalling of the concrete ceiling beneath the point of impact on the Unit 1 refueling floor. The licensee assembled a root cause investigation team to review the event and determine its root cause. The licensee also commissioned the services of an independent structural engineer to analyze the structural integrity of the floor at the point of impact to determine if the floor still met its design criteria.

The inspectors completed a walkdown of the affected areas, accompanied by a civil engineer from the licensee's staff, to view the cracked and spalled concrete from the ceiling below the point of impact. The inspectors also toured the plant and the main control rooms to assess the condition and status of safety-related systems. The inspectors discussed the issue with licensee management, engineering, and operations personnel to assess immediate actions taken and gain an understanding of the detailed inspections completed by licensee personnel. The inspectors also assessed compliance with the reporting requirements of NUREG-1022, Event Reporting Guidelines.

The inspectors later reviewed the licensee's root cause determination report to assess details, accuracy, and short and long term corrective actions. The inspectors noted that the root cause report was thorough, detailed, and comprehensive. The planned and completed actions were appropriate and comprehensive. The licensee identified several root and contributing causes. Root causes included inadequate work practices by the contractor support personnel, and improper installation and verification of the rigging in that the synthetic slings used in the lift were not adequately protected.

The inspectors compared the root and contributing causes with information obtained from the review of licensee work control documents, procedures, briefing papers listed in the attachment, and discussions with licensee personnel. The procedure to remove the old trolley and install the new trolley was revised several times prior to its implementation. However, the rigging crew was not made aware of the final revision and did not implement all of the requirements to use “softeners” to protect the slings and that a line of sight be maintained to ensure that their effectiveness was maximized.

A single sling was rigged around the trolley support beam with five protective softeners. The softeners were verified at the beginning of the move but not during the move, as specified by the rigging permit. Photographs showed that at least one softener at the trolley beam was not in a position to protect the sling after the load was applied. As the old trolley was lowered close to the new trolley, which was staged in preparation for its installation, workers were concerned about possible interference between them. The contract project lead engineer determined that there would be additional clearance if one end of the old trolley was lowered. There was no discussion or intervention by the TVA task manager, supervisor, or safety observer, even though at the pre-job briefing it was emphasized that the load was to be maintained level. The trolley descent had been halted several times to level the load. When one end of the trolley was lowered, the edge of the trolley beam cut the single rigging sling and the trolley fell. Almost immediately, one of the slings on the other end of the trolley failed and the trolley fell to the refuel floor.

Analysis: The inspectors determined that the licensee’s inadequate procedure and poor work performance which resulted in the Reactor Building crane trolley drop that occurred on October 24, 2004, constituted a performance deficiency and a finding. This finding is greater than minor because it is associated with program and process attributes and affected the objective of the Initiating Event Cornerstone to limit the likelihood of those events that upset plant stability and challenge critical safety functions during at-power operations. In addition, if left uncorrected, this finding would result in a more significant safety concern because structural damage to the refuel floor as well as potential damage to the spent fuel pool would occur if the load had dropped from a higher elevation. This finding did not represent an immediate safety concern. This finding was evaluated using the SDP and was determined to be a finding of very low safety significance because no initiating event or transient actually occurred, there was no permanent structural damage to the refuel floor, there was no functional degradation, and mitigating capability was not affected. The inspectors also determined that the cause of this finding was related to the human performance cross-cutting area.

Enforcement: 10 CFR 50 Appendix B, Criterion V, states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, inadequate procedures (not using the latest approved revision to the procedure) and poor human performance resulted in the drop of the Reactor Building crane on October 24, 2004. Because this failure to comply with 10 CFR 50, Appendix B, Criterion V, is of very low safety significance and has been entered into the licensee’s corrective action program, as PER 70752, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000260, 296/2004005-02, Inadequate Procedure and Poor Human Performance Resulted in a Drop of the Reactor Building Crane Trolley.

1R19 Post-Maintenance Testing (PMT)

a. Inspection Scope

The inspectors evaluated the following six activities by observing testing and/or reviewing completed documentation to verify that the PMT was adequate to ensure system operability and functional capability following completion of associated work. The inspectors reviewed licensee procedure SPP-6.3, Post-Maintenance Testing, to verify that testing was conducted in accordance with procedure requirements. The review included the following:

- Unit 3: PMT on Level Switch 71-5H return valve packing replacement (RCIC) per WO 04-715103
- Unit 3: PMT on EECW pump B3 impeller adjustment following test failure per procedure 3-SI-4.5.C.1
- Unit 2: PMT for 2A RHR Hx following eddy current analysis per MCI-0-074-HEX001, Maintenance of RHR Heat Exchangers and 2-SR-3.5.1.6(RHR I-Comp), RHR Loop I Comprehensive Pump Test
- Unit 2: PMT for 2-MVOP-074-0001, RHR Pump 2A Suppression Pool Suction Valve per EPI-0-000-MOV001, Electrical Preventive Maintenance for Limitorque Motor Operated Valves.
- Unit 3: PMT for cap replacement on test connection upstream of drain pot CPOT-5 (RCIC), per WO 04-719199
- Unit 2: PMT for 2-MVOP-075-050, Core Spray Loop II Test Bypass Valve per 2-SR-3.5.1.6(CS II Comp), Core Spray Loop II Comprehensive Pump Test, per WO 04-722184

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors either witnessed portions of surveillance tests or reviewed test data for the seven risk-significant SSCs listed to verify that the tests met TS surveillance requirements, UFSAR commitments, and in-service testing (IST) and licensee procedure requirements. The inspectors' review was to confirm that the testing effectively demonstrated that the SSCs were operationally capable of performing their intended safety functions. IST data was compared against the requirements of licensee procedures 0-TI-362, Inservice Testing of Pumps and Valves, and 0-TI-230, Vibration Monitoring and Diagnostics. The inspectors also reviewed procedure ODM 3-3, Pre-Evolution, Mid-, and End-of-Shift Briefings, to verify that procedure requirements were met for the surveillance activities. The surveillances witnessed or reviewed included the following:

- 3-SR-3.5.3.3, RCIC Rated flow at Normal Operating Pressure *
- 3-SR-3.8.1.1(3B) Diesel Generator 3B Monthly Operability Test
- 3-SR-3.3.5.1.6(ADS B) ADS Logic System Functional Test - Bus B Time Delay Relay Calibration and Bus Power Monitor Test
- 3-SR-3.3.6.1.3(4D) RCIC Steam Line Space High Temperature Calibration
- 2-SR-3.6.1.3.5(RHR I) RHR System MOV Operability Loop I
- 2-SR-3.5.1.6(RHR I-Comp) RHR Loop I Comprehensive Pump Test
- 2-SR-3.4.5.2, 3, 4(1), and (4) (2), Drywell Leak Detection Monitor Source Calibration, Flow rate, and Functional Test.

*This procedure included inservice testing requirements

b. Findings

.1 Inadvertent Start of Emergency Core Cooling System

Introduction: A Green self-revealing NCV was identified for the Failure to Comply with Unit 2 TS 5.4.1, Procedures. As a result of poor work practices, a human performance error occurred and an inadvertent start of the Residual Heat Removal Pump 2B initiated.

Description: On September 20, licensee personnel were in the process of performing surveillance procedure 2-SR-3.3.5 (LPCI II), step 7.7. This step required continuity readings between terminals 1 and 5 on relay 2-RLY-074-10AK118B. Technicians had properly “flagged” the relay and conducted a “peer” check prior to placing the ohm meter leads between contacts 1 and 5. At this point, the technicians removed the ohm meter leads to verify that the meter was set properly to obtain the desired readings. During the process of replacing the ohm meter leads back on contacts 1 and 5 of the original relay, one lead was placed on terminal 1 of the correct relay. However, the other ohm meter lead was placed on contact 5 of relay 2-RLY-074-10AK112B, an incorrect relay. This incorrect act resulted in the inadvertent start of RHR pump 2B. The licensee’s review of the event identified that the apparent causes were a failure to use self-checking techniques and first/second person verification. In addition, the second person assigned for this job was not sufficiently engaged in the work to identify the error-likely situation.

The inspectors discussed the event with operations and engineering personnel and licensee management. The inspectors reviewed operator logs and monitored control room system indications and verified that system response was as expected (flow increased, pressure increased, etc.). The inspectors also reviewed the system alignment following recovery actions to verify that the system and components were in the required standby configuration. The inspectors later reviewed the actions specified in PER 69022 to correct this and prevent similar events. The inspectors also reviewed NUREG-1022, Event Reporting Guidelines, to verify that actions taken were in accordance with the requirements.

Analysis: The inspectors determined that, due to poor human performance, the licensee failed to correctly implement a surveillance test procedure, which resulted in challenging the Emergency Core Cooling Systems (ECCS) with the inadvertent start of RHR pump

2B. This constituted a performance deficiency and a finding. This finding is greater than minor because it is associated with program and process attributes and affected the objective of the Initiating Event Cornerstone to limit the likelihood of those events that upset plant stability and challenge critical safety functions during at-power operations. This finding was evaluated using the SDP and was determined to be a finding of very low safety significance because there was no actual loss of safety function, all aspects of the ECCS remained fully functional, and other redundant ECCS were available to fulfill their safety function. The inspectors determined that the cause of this finding impacted the human performance cross-cutting area.

Enforcement: Unit 2 TS 5.4.1, Procedures, require that written procedures be established, implemented and maintained covering specific activities. One of these activities is the applicable procedures recommended in RG 1.33, Revision 2, Appendix A, February 1978. RG 1.33, Section 8.b.2.(j), identifies testing of Emergency Core Cooling Systems (ECCS). Contrary to this, on September 20, 2004, technicians, due to human performance errors, failed to correctly implement a test procedure for the Unit 2 Low Pressure Coolant Injection system. As a result, an inadvertent start of the Residual Heat Removal Pump 2B occurred. This finding is of very low safety significance because there was no actual loss of safety function, all aspects of the ECCS remained fully functional, and other redundant ECCS were available to fulfill their safety function. Because this failure to comply with TS 5.4.1 is of very low safety significance and has been entered into the licensee's corrective action program as PER 69022, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000260/2004005-03, Poor Work Practices Resulted in a Failure to Follow Procedure and an Inadvertent Start of RHR.

.2 Loss of Safety-Related 480-Volt Shutdown Board 2A and Inadvertent Start of ECCS.

Introduction: A Green self-revealing NCV was identified for the failure to comply with Unit 2 TS 5.4.1, Procedures. As a result of poor work practices during a relay calibration procedure, a human performance error occurred, resulting in the normal supply breaker for a safety-related board (480-volt shutdown board 2A) to trip. This caused the loss of the board, initiated a ½ Scram and Primary Containment Isolation Signal, and started the Control Room Emergency Ventilation and Standby Gas Treatment systems.

Description: On September 28, licensee personnel were in the process of performing a relay calibration for 480-volt shutdown board 2A using procedures 2-ETU-SMI-3-48SDA and 2-ETU-SMI-4-48SDAM, and Work Orders 04-718150-000 and 04-71815-000. During the process of removing the cover for the "C" phase over-current relay for the board's normal supply breaker, the relay was bumped with the relay cover. As a result, power to the board was lost and multiple TS LCOs were entered. This event initiated Engineered Safety Features and caused the loss of systems important to safety on all three units. Some of the equipment lost included the following: Control Air Compressor "G," Unit 2 RHR Loop 1 Low Pressure Coolant Injection, multiple Appendix R Safe Shutdown equipment, Control Bay Chiller 3A, and Reactor Building Closed Cooling Water Pump 2A. In addition, the Reactor Protection and Primary

Containment Isolation systems actuated and Control Room Emergency Ventilation and Standby Gas Treatment systems initiated. The inspectors noted that operations personnel had responded to the event and re-energized the board within about six minutes.

The inspectors reviewed system response and verified that the actions which occurred were expected. The inspectors also walked down the control rooms and verified that system recovery actions were as specified by procedure and that TS-required actions were properly initiated. The inspectors discussed the event with operations personnel, engineering, and licensee management. The inspectors later reviewed PER 69490 to verify that the event description, causes, and proposed corrective actions were appropriate. The licensee's review identified that human performance, over-confidence in the ability to perform the relay cover removal, was the apparent cause. The inspectors did not identify any deficiencies with the licensee's review. This event occurred during the calibration of the last of a series of three relays to be calibrated. The inspectors also reviewed NUREG-1022, Event Reporting Guidelines, to verify that actions taken were correct.

<u>Analysis</u>: The inspectors determined that the error resulted in failing to correctly implement the procedure which challenged Engineered Safety Features and systems important to safety during the inadvertent loss of the safety-related 480-volt shutdown board 2A. This constituted a performance deficiency and a finding. This finding is greater than minor because it is associated with program and process attributes and affected the objective of the Initiating Event Cornerstone to limit the likelihood of those events that upset plant stability and challenge critical safety functions during at-power operations. This finding was evaluated using the SDP and was determined to be a finding of very low safety significance because of the short duration of the event (approximately six minutes), other redundant safety features were available and remained fully functional, and there was no loss of safety function. The inspectors determined that the cause of this finding impacted the human performance cross-cutting area.

<u>Enforcement</u>: Unit 2 TS 5.4.1, Procedures, requires that written procedures be established, implemented, and maintained covering specific activities. One of these activities is the applicable procedures recommended in RG 1.33, Revision 2, Appendix A, February 1978. RG 1.33, Section 8.b.2.(q), identifies testing of Emergency Power systems. Contrary to this, on September 28, 2004, technicians, due to human performance, failed to correctly implement a test procedure during relay calibration for safety-related shutdown board 2A. As a result, the normal supply breaker for the 2A 480-volt shutdown board tripped. Because this failure to comply with TS 5.4.1 is of very low safety significance and has been entered into the licensee's corrective action program as PER 69490, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000260/2004005-04, A Human Performance Error Resulted in the Loss of Safety-Related 480-Volt Shutdown Board 2A and the Inadvertent Start of ECCS Equipment.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed licensee procedures 0-TI-405, Plant Modifications and Design Change Control; 0-TI-410, Design Change Control; SPP-9.5, Temporary Alterations; and the three temporary modifications listed below to ensure that procedure and regulatory requirements were met. The inspectors reviewed the associated 10 CFR 50.59 screening against the system design bases documentation to verify that the modifications had not affected system operability/availability. The inspectors conducted a document review or, where possible, walked down selected portions of the work activities to verify that installation was consistent with the modification documents and the Temporary Alteration Control Form (TACF). Additional documents reviewed are listed in the Attachment. The TACFs reviewed included the following:

- TACF 2-04-009-024, Temporary Leak Repair on Valve BFN-2-THV-024-0762
- TACF 1-04-014-064, Air Supply for Unit 1 Coating Activities, Install temporary flanges, with shutoff valves and piping, in spare penetrations and maintain secondary containment during coating activities
- TACF 0-04-007-082, Jumper CAK contact on the Diesel Generator Governor/Stop relays 82/EXCX, for EDGs A, C, and D

b. Findings

No findings of significance were identified

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed licensee performance during an Orange Team training drill on October 13. Observations included operator performance in the control room simulator and emergency responder performance in the technical support center. The drill focused on degraded plant conditions that led to implementation of the Emergency Operating Procedures and to a Site Area Emergency classification. The drill did not include any participation from state and local government agencies. The inspectors' review was to verify proper implementation of licensee procedures NP-REP, Radiological Emergency Plan, Browns Ferry Emergency Plan Implementing Procedures, SPP- 3.5, Regulatory Reporting Requirements, and OPDP-1, Conduct of Operations. The inspectors assessed operator performance, formality of communications, event classifications, and offsite emergency notifications to verify that they were in accordance with the requirements of the referenced procedures. In addition, procedure usage, alarm response, control board manipulations, and supervisory oversight were evaluated to verify that the procedure requirements were met. The inspectors also reviewed drill documents to verify that drill evaluations focused on improvement items identified during previous drills. The inspectors attended the post-exercise critiques and reviewed the licensee's post-drill report to verify that the licensee-identified issues were comparable to issues identified by the inspectors. The inspectors reviewed the drill objectives to verify that licensee performance fulfilled the requirements of the objectives.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

Cornerstones: Mitigating Systems, Initiating Events

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting PIs, including Procedure SPP-3.4, Performance Indicator for NRC Reactor Oversight Process, Revision 0, for compiling and reporting PIs to the NRC. The inspectors reviewed raw PI data for the PIs listed for the second quarter 2003 through the first quarter 2004. The inspectors compared graphical representations from the most recent PI report to the raw data to verify that the data was correctly reflected in the report. The inspectors reviewed licensee procedure SPP 6.6, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting - 10 CFR 50.65; relevant category A and B PERs; relevant engineering evaluations and associated PERs; and licensee records to verify that the PI data was appropriately captured for inclusion into the PI report, and that the PI was calculated correctly. Additional documents reviewed are listed in the Attachment. PIs reviewed included the following:

- Unit 2 Safety System Unavailability - High Pressure Injection
- Unit 3 Safety System Unavailability - High Pressure Injection
- Unit 2 Unplanned Scrams With Loss of Normal Heat Sink
- Unit 3 Unplanned Scrams With Loss of Normal Heat Sink
- Unit 2 Unplanned Scrams per 7000 Critical Hours
- Unit 3 Unplanned Scrams per 7000 Critical Hours

b. Findings

No findings of significance were identified.

4OA2 Identification & Resolution of Problems

.1 Daily Reviews

As required by Inspection Procedure 71152, Identification and Resolution of Problems, and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. This review was accomplished by reviewing daily PER summary reports and attending daily PER review meetings.

.2 Focused Annual Sample Review

a. Inspection Scope

The inspectors reviewed PERs and work documents associated with some failures of Emergency Diesel Generator (DG) field flashing relays and with Unit 2 HPCI suction swapover events. The inspectors assessed licensee actions to verify that timely and appropriate actions were taken to identify and correct the recurring problems. PERs and associated documents were reviewed in detail to ensure that the full extent of the issue was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified, prioritized, and completed. The inspectors also evaluated licensee actions against the requirements of the licensee's corrective action program as specified in SPP-3.1, Corrective Action Program, and 10 CFR 50, Appendix B. Additional PERs, evaluations, work orders, and corrective action documents reviewed are listed in the Attachment.

b. Findings and Observations

There were no findings of significance identified during these PI&R Annual Sample reviews.

Diesel Generator Field Flashing Relays:
Since March 2003, there were three failures of the DG exciter relays (EXCX). This relay failure disables the field flashing relay circuit so that the DG is rendered inoperable and will not perform its safety function. In March 2003, the relay coil for DG 3A failed. This relay coil had been in service for a considerable time and is in a normally-energized state. The licensee determined that the failure was attributed to end of insulation life. The failed relay was a GE CR105 which is now obsolete. The failed relay was replaced with a new GE CR305 model and PER 03-004784-000 was initiated. One of the corrective actions for the PER was to replace the remaining DG EXCX relays. On June 14, 2004, the EXCX relay for DG C was replaced. The relay subsequently failed on June 29. The relay was replaced and sent to the supply vendor for failure analysis. The licensee later informed the inspectors that the failure analysis was inconclusive for the failure mechanism. On July 8, the EXCX rely for DG 1A was replaced. At this time the licensee also conducted thermography for all DGs and no additional problems were found. The licensee also completed a "lot" search of the relay and determined that the relays were only used for the DGs. In September 2004, the EXCX relay for DG 1D was replaced.

On November 16, 2004, the relay for DG C failed again and was replaced. The licensee conducted a detailed inspection of the this failed relay and identified an angular difference on the factory normally-closed stationary contacts versus the factory normally-open stationary contacts. The angular difference was oriented in such a manner where it reduced contact separation when the relay was energized. The angular difference appeared to have caused arcing, (there was evidence of arcing on the failed relay) that led to eventual failure of the relay coil.

The inspectors discussed this problem with engineering and viewed a failed relay. The inspectors were informed that, when new relays are purchased, site technicians reoriented a set of contacts to meet the configuration for the required application. This work was a common practice and was performed using vendor-supplied instructions that accompany the new relay. The licensee is now working with the supply vendor to complete a formal root cause determination. Engineering informed the inspectors that additional corrective actions will be initiated if required by the results of the root cause.

The inspectors noted that the licensee initiated a PER to address the problems and determine root cause, provided the failed relay to the vendor for failure analysis, completed inspections and voltage testing on all installed suspect relays, identified the relay problem as a Generic Letter 91-18 (Degraded and Non-conforming) problem, informed all other DG users of the problem, and completed a functional evaluation for the DGs. In addition, as an interim compensatory action, a temporary alteration was completed for all affected DGs (1A, 1C, 1D, 3A, 3B, and 3D) to place a jumper across the field flash permissive contact of the EXCX relays. This was to ensure that the DG field flashing circuit will perform its intended function in the event of a relay coil failure. The inspectors noted that licensee actions appeared to be thorough and detailed and no DG operability concern currently exists.

<u>Unit 2 HPCI Suction Swap-over during Operability Test</u>:
While running the quarterly Inservice Testing surveillance on Unit 2 HPCI, the pump unexpectedly shifted its suction from the Condensate Storage Tank (CST) to the Suppression Pool on three occasions since April of 2000. Following the initial event, the licensee's root cause evaluation determined that the problem was related to entrapped air in the CST level sensing lines and switches, 2-LS-73-56A and -56B. The corrective actions focused on calibration procedure enhancement. A second event occurred in August of 2002. The apparent cause was attributed to a false actuation of the CST level switches caused by high turbine acceleration due to cold start conditions. Corrective actions focused on the CST low level alarm failing to annunciate and submitting a time delay relay addition to the swapover circuit to the Technical Review Committee (TRC) (time delay relay not installed at the time). In December of 2003, an effectiveness review of the April 2000 event was performed and the licensee determined that the root cause was incorrect and that the apparent cause for the August 2002 event was correct. However, later the same month, another CST suction to Suppression Pool swapover occurred during a normal surveillance. The root cause for this event was determined to be most likely related to entrapped air in the CST level sensing switches, 2-LS-73-56A and -56B. This was the same root cause as the 2000 event that Engineering had just determined to be incorrect. Corrective actions focused on calibration procedure enhancement and submitting addition of vent valves to enhance venting to the TRC. In December of 2004, Engineering personnel determined that an adverse slope condition on some of the sensing lines existed which created a tendency for air entrapment in the

sensing lines. The apparent cause was determined to be that the condition existed since original installation. Work orders to re-slope the lines were written and were outstanding at the conclusion of this inspection period.

To assist operators with the problem, the surveillance procedure was revised. Current operating practices to run the surveillance include lifting the motor operated valve (MOV) seal-in circuit leads to make 2-FCV-73-36 isolation valve throttle-capable. Throttling valve 2-FCV-73-36, which is in series with the flow test valve 2-FCV-73-35 spreads the pressure drop across two valves. The inspectors noted that such guidance did not exist in emergency procedure 2-EOI, Appendix 11C, Alternate RPV Pressure Control Systems HPCI Test Mode, which is a stand-alone procedure. The function associated with alternate pressure control is a Maintenance Rule Program function. Therefore, suction valve swapover is captured as a functional failure. Also, the associated out-of-service time for these events contributes to this system being above the plant's unavailability goal.

The inspectors noted that corrective actions, to date, have not resolved the long standing equipment problem. Surveillance procedures were revised to work around the problem; and there has been one root cause determination, superceded by a different root cause, superceded by the original root cause for the same problem. The inspectors also noted that troubleshooting and maintenance activities have not yet been effective in identifying and correcting the problem. However, the inspectors determined that this did not constitute a violation of regulatory requirements of more than minor significance.

.3 Semi-Annual Trend Review

a. Inspection Scope

As required by Inspection Procedure 71152, Identification and Resolution of Problems, the inspectors performed a review of the licensee's corrective action program (CAP) and the two most recent quarterly assessment reports and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in section 4OA2.1, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered a six-month period, although some examples expanded beyond those dates when the scope of the trend warranted. In addition, an independent trend was performed on safety-related breaker performance.

The review also included issues documented outside the normal CAP in major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self-assessment, and maintenance rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's latest quarterly trend reports. Corrective actions associated with a sample of the issues identified in the licensee's trend report were reviewed for adequacy. The inspectors also evaluated the report against the requirements of the licensee's corrective action program as specified in SPP-3.1, Corrective Action Program, and 10 CFR 50, Appendix B. Additional documents reviewed are listed in the Attachment.

b. Assessment and Observations

There were no findings of significance identified. The inspectors evaluated the licensee trending methodology and observed that the licensee had performed detailed reviews. The licensee routinely reviewed cause codes, involved organizations, key words, and system links to identify potential trends in their CAP database. The inspectors compared the licensee process results with the results of the inspectors' daily screening and did not identify any discrepancies or potential trends in the CAP data that the licensee had failed to identify. The inspectors reviewed the departmental quarterly assessment reports for the previous two periods (from April through September 2004) and the noted the following: 1) Radiation Protection reported continuing challenges in improving site dose from the bottom quartile of industry performance. The inspectors have noted an increased attention and awareness of dose and dose reduction efforts. 2) Engineering reported no new trends in equipment performance. 3) Operations reported an increasing trend in unplanned LCO entry due to equipment issues. And 4) Maintenance reported an increasing trend in repeat maintenance. The inspectors noted, based upon the department conclusions, that the departments appeared to differ in their perspective on overall equipment performance.

The inspectors performed an independent trend of breaker performance. This review indicated long standing issues with the Residual Heat Removal Service Water (RHRSW) sump pump B associated with RHRSW pump compartment C. The review specifically focused on PER's 03-021540 and 03-021225 and seven Maintenance WOs (listed in the Attachment) associated with this safety-related equipment with repeat breaker trip problems. The inspectors noted that on November 5, 2003, the licensee had initiated a 'trend' PER (03-021540 Level C) for repetitive failures of the pump. It was not clear whether the problem originated with the pump or pump breaker. This trend PER was closed to a previously written PER (03-021225, Level C) and WO# 03-021224 with no additional actions taken. The WO replaced some breaker sub-components and the PER stated to monitor the performance of the A sump pump (the redundant pump) for 90 days. The PER was closed on June 23, 2004. While the A pump was being monitored for problems, at least three different WOs associated with the B pump and breaker occurred. Included was a problem with the pump that resulted in a trip of the 1B RMOV board (refer to PER 63782) when the B sump pump breaker failed to open on June 23, 2004. Review of the available equipment history on the breaker indicates that the first corrective maintenance was performed under WO# 03-012579-000, written on July 9, 2003, for the breaker tripping accompanied by visible smoke and odor in the breaker compartment. Trouble shooting was completed, no problem was found, and the WO was closed. The breaker was worked twice in the following month for the pump failing to run. Breaker subcomponents were replaced each time. Shortly after that, on August 26, 2003, the feeder breaker to the board in which this breaker resides tripped for the first time (see Section 1R12). Currently, there is one open outstanding WO, 04-716696, and all associated PERs were closed and the pump remained out of service under clearance from August 5, 2004, until December 17, 2004. This pump is in the scope of the Maintenance Rule. However, the performance criteria requires both pumps to be unavailable to be a functional failure.

The inspectors noted that, although a performance trend existed and a trend PER was initiated, no specific priority or focused activity occurred by the licensee. Although the licensee actions ensured that the system could perform its function, maintenance, troubleshooting, and corrective actions to correct this problem were not yet effective in reversing the trend.

4OA3 Event Follow-up

.1 Unit 3 SCRAM - November 23

a. Inspection Scope

The inspectors responded to a Unit 3 automatic scram that occurred on November 23. The inspectors discussed the scram with operations, engineering, and licensee management personnel to gain an understanding of the event and assess followup actions. The inspectors reviewed operator actions taken in accordance with licensee procedures and reviewed unit and system indications to verify that actions and system responses were as expected. The inspectors discussed the scram with the licensee's root cause analysis team and assessed the team's actions to gather, review, and assess information leading up to and following the scram. The inspectors later reviewed the initial investigation report and root cause determination to assess the detail of review and adequacy of the root cause and proposed corrective actions prior to unit restart.

The licensee's investigation identified that the root cause of the turbine trip was a loss of turbine speed signal following the turbine/generator response to fault on a 500-kV transmission line. At the end of the inspection period, the licensee was reviewing a previous design change that incorporated a feature to monitor speed probe sensor input such that a failed sensor would not result in a spurious turbine trip. This circuit appeared to have caused the total loss of turbine speed signal. The inspectors also reviewed the initial licensee notification to verify that it met the requirements specified in NUREG-1022, Event Reporting Guidelines. Inspector observations were compared to the requirements specified in the procedure listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Reactor Building Crane Trolley Drop

a. Inspection Scope

The inspectors responded to the Reactor Building Crane Trolley drop that occurred on October 24. The inspectors discussed the event with licensee management, engineering, vendor support, and maintenance personnel to gain an understanding of the conditions leading up to the drop and actions taken immediately following to assess licensee actions. The inspectors reviewed the root cause report to assess the detail and thoroughness of the report and proposed corrective actions. The inspectors also reviewed the event for reportability in accordance with NUREG 1022, Event Reporting Guidelines.

b. Findings

This issue was dispositioned in Section 1R17.

4OA4 Cross-Cutting Issues

Findings documented in Sections 1R17, 1R22.1 and 1R22.2 describe performance deficiencies where the cause or contributing cause was related to the cross cutting area of human performance.

4OA5 Other Activities

.1 Review of Plant Operations Review Committee (PORC) Activities

On November 24, the inspectors attended a PORC meeting to assess licensee activities with respect to review and approval of Unit 3 status for restart following a unit scram. The inspectors reviewed the unit restart checklist and monitored unit condition and status to verify restart readiness. The inspectors also reviewed selected TS requirements to verify that they had been completed and met regulatory requirements. The inspectors reviewed the licensee's Nuclear Quality Assurance Plan, TVA-NQA-PLN89A, Section 9.9, Plant Reviews, to verify that program requirements were met during the PORC meetings. No findings of significance were identified.

.2 (Closed) Violation 05000259,260,296/2001002-01: TVA Corporate Employee Discrimination

On February 7, 2000, a Severity Level II violation with civil penalty was issued to the licensee. The violation was not site-specific and involved employment discrimination contrary to the requirements of 10 CFR 50.7, "Employee Protection," in that TVA did not select a former employee to a competitive position in a corporate organization in 1996, due, at least in part, to his engagement in protected activities. In addition two Severity Level II violations of 10 CFR 50.5, Deliberate Misconduct, were issued to the individual TVA managers involved in the employment discrimination. On January 22, 2001, TVA denied the violation. On May 4, 2001, an Order was issued sustaining the violation and imposing the civil penalty. On June 1, 2001, TVA appealed the case to the Atomic Safety and Licensing Board (ASLB). From April to September, 2002, a hearing was held before the ASLB. On June 26, 2003, the ASLB upheld the Nuclear Regulatory Commission (NRC) staff's finding that TVA discriminated against its former employee. The decision of the ASLB was appealed to the Commission by TVA. On August 18, 2004, the Commission affirmed in part and reversed in part the ASLB decision and remanded the case back to the ASLB. On October 29, 2004, a Settlement Agreement was signed by TVA and the NRC staff. In the Agreement, the NRC withdrew the two individual violations, dropped the civil penalty, and agreed not to pursue a related individual case, while TVA agreed not to further contest the violation against the company and submit to a review by the NRC of recently completed TVA audits in the area of safety conscious work environment (SCWE) and the training of managers. The Settlement Agreement was subsequently signed by the ASLB on November 10, 2004. On November 30, 2004, the NRC Office of Enforcement (OE) conducted a review at the TVA Nuclear (TVAN) offices in Chattanooga, Tennessee, and at TVA's Sequoyah Nuclear Power Plant to verify TVA's corrective actions relative to the Settlement

Agreement. In a letter dated January 12, 2005, OE concluded that the corrective actions were appropriate and adequately implemented and that TVA appears to actively support a SCWE. On December 20, 2004, the Commission declined to review the ASLB's decision; thereby, making the ASLB's decision the final agency action. This violation is therefore closed.

4OA6 Management Meetings

Exit Meeting Summary

On January 18, 2005, the resident inspectors presented the inspection results to Mr. M. Skaggs, Mr. K. Krueger, and other members of his staff. The inspectors confirmed that proprietary information reviewed by the inspectors during the inspection period was returned to the licensee.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

B. Aukland, Assistant Nuclear Plant Manager
T. Abney, Nuclear Site Licensing & Industry Affairs Manager
L. Clardy, Site Nuclear Assurance Manager
R. Jones, Unit 1 Restart Manager
K. Krueger, Nuclear Plant Manager
J. Lewis, Nuclear Plant Operations Manager
B. Marks, Engineering & Site Support Manager
B. Mitchell, Radiation Protection Manager
J. Ogle, Site Security Manager
P. Olsen, Maintenance & Modifications Manager
C. Ottenfeld, Chemistry Manager
M. Skaggs, Site Vice President

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Closed

05000259,260,296/2004005-01	NCV	Failure to Demonstrate that the RMOV Board 1B Performance Was Effectively Controlled per 10 CFR 50.65 (a)(2). (Section 1R12)
05000260,296/2004005-02	NCV	Inadequate Procedures and Poor Human Performance Resulted in a Drop of the Reactor Building Crane Trolley. (Section 1R17)
05000260/2004005-03	NCV	Poor Work Practices Resulted in a Failure to Follow Procedure and an Inadvertent Start of RHR. (Section 1R22.1)
05000260/2004005-04	NCV	A Human Performance Error Resulted in the Loss of Safety-Related 480-Volt Shutdown Board 2A and the Inadvertent Start of ECCS Equipment. (Section 1R22.2)
05000259,260,296/2001002-01	VIO	TVA Corporate Employee Discrimination (Section 40A5).

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

- 2-OI-75 Core Spray System Attachment 1, Valve Lineup Checklist, Attachment 2, Panel Lineup Checklist, Attachment 3, Electrical Lineup Checklist, and Attachment 4, Instrument Inspection Checklist
- 0-OI-57A Switchyard and 4160 AC Electrical System
- 0-OI-57B Attachment 3F, Unit 3, Shutdown Board and Reactor MOV Electrical Lineup Checklist; Attachment 3E, Unit 2, Shutdown Board and Reactor MOV Electrical Lineup Checklist

Section 1R05: Fire Protection

- Fire Hazards Analysis, Volume 1 and 2
- Fire Pre-Plans: RX3-621, RX2-621, DG12-565, DG12-583, CB1-593, CB2-593, CB3-593, CB1-606, CB2-606, CB3-606, CB1-617, CB2-617, CB3-617, RX1-639, RX1-621, RX1-593, RX2-519, RX2-565, RX2-593
- Smoke Detector Locations: Procedure 0-SI-4.11.A.1(3)

Section 1R11.2: Licensed Operator Requalification, Biennial Review

- BFN-TRN-04-009, Focused Self Assessment Report
- Browns Ferry Simulator Transient Tests:
  - Transient # 1 Manual Scram 2003
  - Transient # 3 “Simultaneous Closure of All Main Steam Isolation Valves” 2003
  - Transient # 4 “Dual Recirc Pump Trip” 2003
  - Transient # 9 “Main Steam Line Break Outside Containment” 2003
- Browns Ferry Simulator/Plant Data Comparisons:
  - U3 Scram from 100% Power
  - U2 Scram from 100% Power
- Browns Ferry Simulator Malfunctions:
  - Loss of Shutdown Cooling (2-AOI-74-1)
  - Loss of Control Air (2-AOI-32-2)
  - FW-19 Feed Water Line Break Inside Steam Tunnel
- Browns Ferry Four-Year Simulator Test Report for Period Ending 12/13/2003
- Simulator Problem Reports: PR 4088, 4066, 3976, 3846, 3844
- Simulator Evaluation Guides:
  - OPL 177.073
  - OPL 177.047
- Job Performance Measures: Various
- Written Exams:
  - Biennial SRO Exams - 3W6S, 03C6W4S, 03C6W5S
  - Biennial RO Exams - 3W6R, 03C6W4R, 03C6W5R
- LER 2004-001-00, 09/07/2004
- TRN 11.4, “Continuing Training For Licensed Personnel”
- TRN-11.9, “Simulator Exercise Guide Development and Revision”
- TRN 11.10, “Annual Requalification Examination Development and Implementation”
- TRN 11.11, “Requalification Periodic Written Examination Development and Implementation”
- TRN -11.12, “Job Performance Measures Development Administration and Evaluation Manual”
- TRN-11.14, “TVA Operator Licensing Examination Security Program”
- TRN-12, “Simulator Regulatory Requirements”
- OPDP-1, “Conduct of Operations”
- OSIL-006 R2, 11/24/2004, “Operations Section Instruction Letter Requirements for Returning An Inactive License to Active Status”
- Operation Logs

- CAD Records (4)
- Reactivation Records (4)
- Medical Records (10)
- Operations Daily Instructions (ODIs)

Section 1R12: Maintenance Effectiveness

- Procedure 2/3-SI-4.6.H.1, Visual Examination of Hydraulic and Mechanical Snubbers
- Engineering Evaluation: Inoperable Snubber, 3-SNUB-001-5077
- Engineering Assessment of Snubber Failures During U3C11 Outage
- PER 63782 and WO's 03-016522-000, 04-715493-000, 04-715493-001 and 04-715493-002 related to 1B 480-V RMOV board

Section 1R17.2: Permanent Plant Modifications

- Initial assessment of the Structural Concrete Integrity after the Reactor Building Crane Trolley Drop Accident, dated 10/30/04
- Job Safety Analysis, dated 10/08/04
- Task Safety Analysis, dated 10/24/04
- MSI-0-000-LFT001, Lifting Instructions for the Control of Heavy Loads
- Functional Evaluation 40775, Reactor Building Crane Trolley Accident
- SPP-6.1, Pre-Job Briefings /Post-Job Review
- NUREG-0612, Control of Heavy Loads at Nuclear Power Plants

Section 4OA1: Performance Indicator (PI) Verification

- Desktop Guide for Identification and Reporting of NEI 99-02, Revision 2, Performance Indicators
- SPP-3.4, Performance Indicator for NRC Reactor Oversight Process, Revision 2

Section 4OA2.2: Identification & Resolution of Problems

- PERs 03-004784-000, 64239, 70399, 58272, 57897, 45701, 52376, 52240, and 72934
- Plant drawing 0-45E767-1&2, 0-761E597
- TACF 0-04-007-082
- 10 CFR 50-59 Evaluation, 0-04-007-082, and PERs 70399, 72960
- Unit 2 HPCI System Health Report, 3rd quarter 2004
- PER 58272, 57897, 45701, 52376, 52240, 72934

Section 4OA2.3: Semi-Annual Trend Review

- Licensee PER Data Base
- Chemistry Integrated Quarterly Assessment Report, April-September 2004
- Maintenance/Mods Integrated Quarterly Assessment Report, April-September 2004
- Browns Ferry Trend Summary April-September 2004
- System Health Reports 2nd Qtr 2004
- System Health Reports 3rd Qtr 2004
- Site Engineering Integrated Quarterly Assessment Report, April-September 2004
- Operations Integrated Quarterly Assessment Report, April-September 2004

Section 4OA3: Event Followup

- 3-AOI-100-1, Reactor Scram
- 3-OI-3, Feedwater System
- EOI-1, RPV Control
- 3-SR-3.1.4.1, Scram Insertion Times
- Incident Investigation Report for PER 72670