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

January 30, 2006

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 05000259/2005005, 05000260/2005005, AND 05000296/2005005

Dear Mr. Singer:

On December 31, 2005, 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 10, 2006, with Mr. B. O'Grady and other members of your staff.

Also, please note that, per our letter to you on December 29, 2004, Browns Ferry Unit 1 inspections in the Reactor Oversight Program (ROP) cornerstones of Occupational Radiation Safety, Public Radiation Safety, Emergency Preparedness, and Physical Protection were incorporated into the routine ROP baseline inspection program effective January 1, 2005. Although this report period did not contain any site inspection in those cornerstones, they will continue to be documented in ROP integrated quarterly reports such as this one. Results from our inspection of your Unit 1 Recovery Project in the remaining cornerstones will continue to be 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 two NRC-identified findings of very low safety significance (Green), one of which was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because the finding was entered into your corrective action program, the NRC is treating the violation as a non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy. If you contest the non-cited violation or finding 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 Senior 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 by Joseph W. Shea Acting for/

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

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

Enclosure: Inspection Report 05000259/2005005, 05000260/2005005 AND 05000296/2005005
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

cc w/encl:
Ashok S. Bhatnagar
Senior Vice President
Nuclear Operations
Tennessee Valley Authority
Electronic Mail Distribution

Larry S. Bryant, Vice President
Nuclear Engineering & Technical Services
Tennessee Valley Authority
Electronic Mail Distribution

Brian O'Grady
Site Vice President
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

Robert J. Beecken, Vice President
Nuclear Operations
Tennessee Valley Authority
Electronic Mail Distribution

General Counsel
Tennessee Valley Authority
Electronic Mail Distribution

John C. Fornicola, Manager
Nuclear Assurance and Licensing
Tennessee Valley Authority
Electronic Mail Distribution

Bruce M. Aukland, Plant Manager
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

Glenn W. Morris, Manager
Corporate Nuclear Licensing
and Industry Affairs
Tennessee Valley Authority
Electronic Mail Distribution

William D. Crouch, Manager
Licensing and Industry Affairs
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

State Health Officer
Alabama Dept. of Public Health
RSA Tower - Administration
Suite 1552
P. O. Box 303017
Montgomery, AL 36130-3017

Chairman
Limestone County Commission
310 West Washington Street
Athens, AL 35611

Masoud Bajestani, Vice President
Browns Ferry Unit 1 Restart
Browns Ferry Nuclear Plant
Tennessee Valley Authority
P. O. Box 2000
Decatur, AL 35609

Robert G. Jones, General Manager
Browns Ferry Site Operations
Browns Ferry Nuclear Plant
Tennessee Valley Authority
P. O. Box 2000
Decatur, AL 35609

Distribution w/encl: (See page 4)

Distribution w/encl:
M. Chernoff, NRR
E. Brown, NRR
L. Slack, RII EICS
RIDSRIDSNRRDIPMLIPB
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U.S. NUCLEAR REGULATORY COMMISSION REGION II

Docket Nos:	50-259, 50-260, 50-296
License Nos:	DPR-33, DPR-52, DPR-68
Report Nos:	05000259/2005-005, 05000260/2005-005, 05000296/2005-005
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Units 1, 2, and 3
Location:	Corner of Shaw and Nuclear Plant Roads Athens, AL 35611
Dates:	October 1, 2005 – December 31, 2005
Inspectors:	T. Ross, Senior Resident Inspector R. Monk, Resident Inspector E. Christnot, Resident Inspector
Approved by:	Stephen J. Cahill, Chief Reactor Project Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000259/2005005, 05000260/2005005, 05000296/2005005; 10/01/2005 - 12/31/2005; Browns Ferry Nuclear Plant, Units 1, 2, and 3; Licensed Operator Requalification, Operator Performance During Non-Routine Evolutions and Events.

The report covered a three-month period of routine inspection by resident inspectors. Two findings of significance were identified. The significance of an issue is indicated by its color (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. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a finding for licensee grading errors which resulted in a failure to identify an individual performance issue that would have resulted in an operational test failure during a biennial operating test requalification examination.

  The finding is more than minor because if left uncorrected, it would allow less-than-competent operators to continue licensed duties and it affected the human performance attribute of the Initiating Event Cornerstone. The inspectors evaluated the finding using MC 0609, Significance Determination Process, Appendix I. Using the Operator Requalification Human Performance SDP flow chart, the finding involved the licensee's grading of an exam, in which the licensee failed to identify an individual performance issue which would have resulted in an operational test failure. Per the SDP flowchart, this finding is of low safety significance because it is likely that a single operator's potential error would be prevented or mitigated by the rest of the crew. (Section 1R11)

Cornerstone: Barrier Integrity

C Green. The inspectors identified a non-cited violation of Technical Specifications 5.4.1.a when reactor operators failed to adequately implement all required procedural steps of 3-ARP-9-5A for Rod Block Monitor High, and 3-OI-92C, Rod Block Monitor, on numerous occasions when automatic rod blocks occurred during continuous rod withdrawals for Unit 3 power ascension.

  The finding is more than minor because, if left uncorrected, it would result in a more serious safety concern during an actual rod withdrawal error event, and it affected the human performance attribute for maintaining fuel clad functionality of the Barrier Integrity Cornerstone. However, this finding is of very low safety significance because the minimum critical power ratio safety limit was not violated or approached, and the associated control rods were withdrawn per the required sequence and not in error. The operators' failure to recognize and follow their annunciator response procedures was a cause of the finding and directly involved cross cutting aspects of Human Performance. (Section 1R14)

B. Licensee Identified Findings

None.

Report Details

Summary of Plant Status

Unit 1 was defueled and in a recovery status for the entire report period.

Unit 2 operated at essentially full power for the entire report period.

Unit 3 operated at essentially full power for the entire report period, except for an unexpected reactor trip and two planned shutdowns. On October 31, 2005, Unit 3 experienced an automatic reactor trip from 100% power due to loss of load caused by an main turbine generator (MTG) electro-hydraulic control (EHC) system failure that was initiated when a grounded 500-kV offsite power line was inadvertently returned to service. The unit was restarted on November 8. However, Unit 3 was purposefully shutdown (i.e., manually scrammed) twice over the next few days while the unit was still in Mode 2 due to persistent intermediate range nuclear instrumentation system equipment problems. Unit 3 was returned to full power operation on November 14, 2005.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (Cold Weather Preparation)

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 also reviewed the list of open Problem Evaluation Reports (PERs) to verify that the licensee was identifying and correcting potential problems relating to cold weather operations. The inspectors specifically reviewed PERs associated with incomplete work activities that were identified during cold weather preventive maintenance activities. Furthermore, 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, including residual heat removal service water (RHRSW) and Emergency Equipment Cooling Water (EECW) systems, to verify that affected systems and components were properly configured and protected 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. Furthermore, on December 5 - 7, when the weather dropped below the 32 degree Fahrenheit (EF) and 25EF thresholds, inspectors verified that the applicable equipment walkdown checklists of 0-GOI-200-1 were implemented accordingly.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

Partial System Walkdown The inspectors performed partial walkdowns of the three safety systems listed below to verify train operability as required by the plant Technical Specifications (TSs), while the other redundant or diverse trains were out of service. These inspections included reviews of applicable TSs, plant lineup procedures, operating procedures, and/or piping and instrumentation drawings (P&IDs) which were compared with observed equipment configurations to identify any discrepancies that could affect operability of the redundant train or backup system. The systems selected for walkdown were also chosen due to their relative risk significance from a Probabilistic Safety Assessment (PSA) perspective for the existing plant equipment configuration. The inspectors verified that selected breaker, valve position, and support equipment were in the correct position for system operation.

- Unit 2 High Pressure Coolant Injection (HPCI) per flow diagram PI&D 2-47E812
- B/C Standby Gas Treatment System per flow diagram PI&D 0-47E385-11
- Unit 3 Division I Core Spray System (CSS) per flow diagram PI&D 3-47E814-1

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

Walkdowns The inspectors reviewed licensee procedures, Standard Program and Process (SPP)-10.10, Control of Transient Combustibles, and SPP-10.9, Control of Fire Protection Impairments, and conducted a walkdown of the seven fire areas (FA) and zones listed below. Selected fire areas/zones were examined in order to verify licensee control of transient combustibles and ignition sources; the material condition of fire protection equipment and fire barriers; and operational lineup and operational condition of fire protection equipment or measures. Also, the inspectors verified that selected fire protection impairments were identified and controlled in accordance with procedure SPP-10.9. Furthermore, the inspectors reviewed applicable portions of the Site Fire

Hazards Analysis (FHA), Volumes 1 and 2 and 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.

- Fire Area 4, 4-kV Shutdown Board Room B
- Fire Zone 3-3, Unit 3 Rx bldg, elevation 593
- Fire Area 12, 4-kV Shutdown Board Room F
- Fire Area 5, 4-kV Shutdown Board Room A
- Fire Zone 2-6, Unit 2 Rx bldg, elevation 639 south
- Fire Zone 3-4, Unit 3 Rx bldg, elevation 621
- Fire Zone 2-3, Unit 2 Rx bldg, elevation 593 north

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (LOR)

a. Inspection Scope

On November 14, the inspector observed operator crew conduct during a biennial requalification examination per LOR-Exam-1 to verify that crew performance was in accordance with licensee procedures and regulatory requirements.

The inspector specifically evaluated the following attributes related to the operating crews' performance:

- Clarity and formality of communication
- Ability to take timely action to safely control the unit
- Prioritization, interpretation, and verification of alarms
- Correct use and implementation of Abnormal Operating Instructions (AOI), Emergency Operating Instructions (EOI) and Operational Contingencies
- Timely and appropriate Emergency Action Level declarations per Emergency Plan Implementing Procedures
- Control board operation and manipulation, including high-risk operator actions
- Command and Control provided by the Unit Supervisor and Shift Manager

The inspector also attended the post-exam critique to assess the effectiveness of the licensee evaluators, and to verify that licensee-identified issues were comparable to issues identified by the inspector. In addition, the inspector attended a Training Review Board (TRB) to assess the proposed remedial training.

b. Findings

Introduction: A Green finding was identified by the inspector for licensee grading errors which resulted in a failure to identify an individual performance issue that would have resulted in an operational test failure during a biennial operating test requalification examination.

Description: The inspector observed the Crew 1, Group B, biennial simulator operating test. The crew inappropriately initiated an emergency depressurization (ED) of the reactor due to improper use of EOI-3. The licensee scenario evaluators determined that the crew failed to meet the licensee's performance expectations. In accordance with the licensee's training program procedures, the TRB was required to meet and determine remedial training and retesting for the crew prior to the crew resuming its licensed duties.

The inspector attended the TRB. During discussions of the crew's performance, the inspector learned that Crew 1, Group A, performing the same scenario earlier the same morning, had also initiated an ED in a similar manner, but were considered to have passed by the licensee evaluators. (Note: the evaluators were not the same for each crew.) Followup questioning by the inspectors led to a re-evaluation of Crew 1, Group A performance by the TRB. The TRB subsequently determined that an individual member of that crew had indeed failed and the grading had been in error.

Analysis: The finding is human performance issue involving a grading error which adversely affected the licensee's ability to discriminate between competent and less-than-competent licensed operators. The inspectors referred to Inspection Manual Chapter (IMC) 0612 and determined that the finding is more than minor because if left uncorrected it would allow less-than-competent operators to continue conducting their licensed duties. This finding also affected the human performance attribute of the Initiating Event cornerstone. The inspectors evaluated the finding using the applicable flow chart in IMC 0609, Appendix I, Significance Determination Process (SDP) for Licensed Operator Requalification. According to the flow chart, the significance of the finding was determined to be Green because it involved grading error of an exam in which the licensee failed to identify an individual performance issue that would have resulted in an operational test failure. This finding is of low safety significance because it is likely that a single operator's potential error would be prevented or mitigated by the rest of the crew.

Enforcement: No violation of regulatory requirements occurred. This finding was entered into the corrective action program as PER 93023.

1R12 Maintenance Effectiveness

Routine Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the two systems listed below with regard to some or all of the following attributes: (1) 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) appropriateness of performance criteria in accordance with 10 CFR 50.65(a)(2), (8) system classification in accordance with 10 CFR 50.65(a)(1); and (9) appropriateness and adequacy of goals and corrective actions (i.e., Ten Point Plan) for Structures, Systems, and Components (SSCs)/functions classified as (a)(1). The inspectors also compared the licensee's performance against site procedure SPP-6.6, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting; Technical Instruction 0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting; 0-TI-362, Inservice Testing of Pumps and Valves; and SPP 3.1, Corrective Action Program. The inspectors also reviewed applicable work orders, PERs, engineering evaluations, MR expert panel minutes, and system testing, and attended MR expert panel meetings to verify that regulatory and procedural requirements were met.

- Unit 2 & 3 Residual Heat Removal Service Water (RHRSW) and Emergency Equipment Cooling Water (EECW) Motors (Unavailability)
- Unit 2 HPCI (Maintenance Preventable Functional Failure) due to failure of 2-MOV-73-30 (PER 91422)

b. Findings

No findings of significance were identified

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

j. Inspection Scope

For the six risk and emergent work assessments of the out of service (OOS) equipment and systems listed below, the inspectors reviewed licensee actions taken to plan and control 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) and applicable licensee procedures such as, SPP-6.1, Work Order Process Initiation, SPP-7.1, Work Control Process and 0-TI-367, BFN Dual Unit Maintenance. The inspectors also evaluated the adequacy of the licensee's risk assessments and the implementation of compensatory measures.

- Work activities associated with the Unit 3 forced outage
- 3A RHR Pump and Heat Exchanger, RHR Crosstie Valves 74-101, Common Service Station Transformer A, 2B Fire Water Pump, and B Emergency Diesel Generator OOS
- Unit 3 O_2 Analyzers OOS for Start Up
- 3A Control Rod Drive (CRD) Pump, 3C EECW Pump, RHR Crosstie Valve 74-101, and A SBGT OOS
- 3B/3D CSS Pumps, 3A CRD Pump, RHR Crosstie Valve 74-101, A SBGT, and Multiple 500-kV Offsite Power Lines OOS

- Unit 3 HPCI outage, with D3 EECW pump, RHR Crosstie Valve 74-101, and Madison 500-kV line OOS

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events

a. Inspection Scope

For the non-routine evolutions described below, the inspectors evaluated operator performance through interviews, observations, examining available information (e.g.,operator logs, plant computer data, and strip charts), and reviewing applicable PERs to determine what occurred, how the operators responded, and to verify that the response was in accordance with plant procedures (e.g., normal operating instructions (OIs), annunciator response procedures (ARPs), and AOIs, etc.).

.1 Unit 3 Automatic Scram

On October 31, 2005, the inspectors responded to the Unit 3 control room following an automatic scram from 100% power due to a main turbine trip. The inspectors discussed the event with licensee management, and Engineering, Operations, and other licensee personnel to gain an understanding of the events leading up to the scram and actions immediately following the scram. The inspectors' review was to verify that operator actions were in accordance with licensee procedures and regulatory requirements.

Just prior to the reactor/turbine trip, operators were in the process of returning 500-kV switchyard Bus-2, Section 2, to service using a switching order. When the power circuit breaker (PCB) to the 500-kV Trinity 2 transmission line was closed, it immediately and unexpectedly tripped back open. The PCB tripped open per design to clear a hard ground on the Trinity 2 line due to a grounding device that was inadvertently left installed at a remote sub-station. The serious electrical power transient resulting from the ground, and its clearing, caused the Unit 3 main turbine to trip.

The ground on the Trinity 2 line was due to a human performance error by Power Service Organization (PSO) personnel of the licensee's transmission group who did not recognize that there was an active switching order still in effect on the 500-kV Trinity 2 line when Browns Ferry Operations was notified to re-energize the line. This offsite PSO organization was responsible for the switching order development and implementation. The PSO continues to investigate the root cause of this incident and the results will be documented in PER 91811. Human performance issue(s) associated with this event will be addressed by the inspectors in the pending licensee event report (LER) closeout process.

The inspectors observed operator performance in the control room during post-scram activities. The activities observed included securing of unneeded equipment, re-alignment of equipment necessary to ensure stable unit operation, verification of equipment status and parameters required by TSs, and monitoring of critical systems to ensure that the equipment was ready for automatic operation. The inspectors' observations were compared to 2-AOI-100-1, Reactor Scram and various other annunciator response procedures in use to verify that procedure and regulatory requirements were met. The inspectors examined critical equipment and system parameters to verify that system and equipment response during and after the scram. (See 4OA3.1 regarding event followup.)

.2 Unit 3 Manual Shutdown and Reactor Scram From Mode 2

On November 8, during restart of Unit 3 following the reactor trip of October 31, the inspectors witnessed a manual reactor scram of Unit 3 while the unit was still in Mode 2 and subcritical. The decision to abort the startup, manually scram the unit, and return to Mode 3 conditions was conservatively made by Operations management due to continuing equipment performance issues with several of the nuclear instrumentation system intermediate range monitors (IRMs). The inspectors observed reactor operator conduct in accordance with 3-AOI-100-1, Reactor Scram. The inspectors also monitored operator response to anticipated annunciator alarms, and operator actions to ensure stable Mode 3 conditions. Furthermore, the inspectors examined operator response to address unexpected problems associated with the failure of multiple groups of control rod accumulator lights to clear following the scram.

.3 Unit 3 Startup and Power Ascension

During the second week of November 2005, the inspectors witnessed operator performance during two Unit 3 startups, which included the approach to criticality, synchronizing the main generator to the grid, and power ascension. The inspectors observed operators perform appropriate system verifications and alignments for startup in accordance with licensee procedures (e.g., 3-GOI-100-1A, Unit Startup and Power Operation) and TSs. The inspectors also reviewed completed licensee procedures and monitored control room indications to verify TS requirements were met prior to and during restart, and power ascension.

.4 High Voltage Switchyard Switching Operations

On October 24, December 2, and December 7, the inspectors observed licensed operators conduct switching operations to realign 161-kV and 500-kV switchyard breakers as necessary to remove and/or return to service offsite power lines in support of Unit 1 recovery activities in accordance with approved switching orders. The inspectors attended the associated pre-job briefings, reviewed the applicable switching orders (e.g., switching order 1322), and witnessed their execution. The inspectors also examined the close coordination and communications between onsite shift operations and responsible PSO personnel.

b. Findings

Introduction: A Green NRC-identified violation of TS 5.4.1.a for failing to implement all the required procedural steps of annunciator response procedure (ARP) 3-ARP-9-5A for Rod Block Monitor High, and normal operating instruction (OI) 3-OI-92C, Rod Block Monitor, on numerous occasions when rod blocks occurred during continuous rod withdrawals for Unit 3 power ascension.

Description: On November 10, during the power ascension of Unit 3, while reactor power was approximately 33%, the inspectors witnessed reactor operators conduct numerous continuous control rod withdrawals from the 00 notch position (i.e., fully inserted) to notch position 48 (i.e., fully withdrawn). During these continuous rod pulls, many of the control rods were of sufficiently high reactivity worth as to cause an initiation of an automatic rod block by the rod block monitor (RBM). Each time this occurred, the inspector observed the operator acknowledge and announce the associated annunciator alarms; promptly reset and reinitialize the RBM normalized setpoints by turning the control rod panel off and on, and re-select the desired control rod; and then immediately proceed with the rod pull. This sequence of operator actions was observed multiple times with no apparent referral to the applicable ARPs or 3-OI-92C. Subsequent interviews with responsible operators, unit supervisors, shift managers, and operator training personnel revealed that the sequence of operator actions witnessed by the inspectors has been a standard practice. However, according to 3-ARP-9-5A for RBM High, and 3-OI-92C, operators should have stopped, taken specific steps to assess any potential adverse impact due to the high flux condition (e.g., examine local power range monitor (LPRM) reading log, review core thermal limits), and implement corrective action to reduce the high flux conditions.

Analysis: During high power operation (i.e., greater than 27% power), the RBM is required by TS to be operable in order to provide protection for control rod withdrawal error (RWE) events. More specifically, the purpose of the RBM is to limit control rod withdrawal if localized neutron flux exceeds a predetermined setpoint during control rod manipulations. It is assumed to function to block further control rod withdrawal to preclude violating the minimum critical power ratio (MCPR) safety limit. Operator actions observed by the inspectors were inconsistent with the intended purpose of the RBM and demonstrated a nonconservative operating practice. Although subsequent review by the licensee confirmed that no thermal limits (i.e., MCPR) were violated or approached during these continuous rod pulls, the observed operator actions constituted a failure to follow established procedures. According to IMC 0612, the inspectors determined that this finding is more than minor because, if left uncorrected, it would result in a more serious safety concern during an actual RWE event. However, according to IMC 609, Appendix A, Phase 1 significance determination screening, this finding is of very low safety significance, because the MCPR safety limit was not violated or approached, and the associated control rods were withdrawn per the required sequence. The operators' failure to recognize and follow their annunciator response procedures was a cause of the finding and directly involved cross cutting aspects of Human Performance.

Enforcement: Technical Specification 5.4.1.a requires written procedures be established, implemented, and maintained covering activities specified in Regulatory Guide (RG) 1.33, Appendix A. Item 5 of RG 1.33, Revision 2, Appendix A, requires procedures for off-normal and alarm conditions. Contrary to TS 5.4.1.a, reactor operators did not adequately implement the procedural steps and instructions of 3-ARP-9-5A and 3-OI-92C. Because this human performance error is of very low safety significance and has been entered in the corrective action program as PER 92719, this violation is being treated as a noncited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy; NCV 05000296/2005005-02, Failure to Follow Procedure in Response to Automatic Rod Blocks.

1R15 Operability Evaluations

Routine Baseline Review

a. Inspection Scope

The inspectors reviewed the two operability/functional evaluations listed below to verify technical adequacy and ensure that the licensee had adequately assessed TS operability. The inspectors reviewed appropriate sections of the UFSAR to verify that the system or component remained available to perform its intended function. In addition, 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. Furthermore, where applicable, inspectors reviewed implemented compensatory measures to verify that they worked as stated and that the measures were adequately controlled. The inspectors also reviewed PERs daily to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

- 3-RM-090-272A Radiation Monitor (PER 90708)
- 3D Emergency Diesel Generator (PER 90202)

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (PMT)

a. Inspection Scope

The inspectors witnessed and/or reviewed documentation of post-maintenance test (PMT) activities of the six risk significant SSCs listed below to verify that system operability and functional capability following completion of associated work was adequately demonstrated. For each of these PMTs, some or all of the following aspects were inspected: (1) effect of testing on the plant was recognized and addressed by control room, maintenance and/or engineering personnel; (2) testing was consistent with maintenance performed; (3) acceptance criteria demonstrated operational readiness consistent with design and licensing basis documents such as TSs, UFSAR, and others; (4) range, accuracy and calibration of test equipment; (5) step by step compliance with test procedures, and applicable prerequisites satisfied; (6) control of installed jumpers or lifted leads; (7) removal of test equipment; and, (8) restoration of SSCs to operable status. The inspectors also verified that PMT activities were conducted in accordance with applicable procedural requirements, including SPP-6.3, Post-Maintenance Testing, and MMDP-1, Maintenance Management System. Furthermore, the inspectors also reviewed problems associated with PMTs that were identified and entered into the corrective action program.

- Unit 2 HPCI Pump Mini-Flow per 2-SR-3.6.1.3.5(HPCI), HPCI System Motor Operated Valve Operability.
- RHRSW Pump A2 Breaker per Work Order 05-722517-000 and OI-23, RHRSW Operating Instructions
- Reactor Zone Damper 2-FCO-064-10 replacement per 0-SR03.6.4.2.1, Secondary Containment Isolation Valve Stroke Timing
- Unit 3 Main Steam Isolation Valve (MSIV) A (outboard) per 3-SR-3.6.1.3.6, MSIV Fast Closure, 3-SR-3.3.1.1.8(5), MSIV Closure-RPS Trip Channel Functional Test and 3-SR-3.3.1.1.13(outbd), Outboard MSIV Limit Switch Calibration and Slow Speed Adjustment
- Unit 3 MSRV Pilot Replacement per 3-SR-3.4.3.2, MSRV Manual Cycle Test
- C1 RHRSW Pump impeller adjustment per 2-SI-4.5.c.1(3), RHRSW Pump and Header Operability and Flow Test.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

Unit 3 Unscheduled Outage

a. Inspection Scope

During first two weeks of November, the inspectors examined critical outage activities to verify that they were conducted in accordance with TSs, applicable procedures, and the licensee’s outage risk assessment and management plans. Some of the more significant inspection activities accomplished by the inspectors were as follows:

- Verified operability of reactor coolant system (RCS) pressure, level, and temperature instruments during various modes of operation
- Monitored important control room plant parameters
- Verified shutdown cooling systems operation
- Evaluated implementation of reactivity controls

- Verified that status and configuration of electrical systems met TS requirements and outage risk control plan.

Containment Closeout

The inspectors performed detailed closeout inspections of the Unit 3 drywell and reviewed licensee implementation of 3-GOI-200-2, Drywell Closeout, prior to plant startup.

Heatup, Mode Transition, Reactor Startup, and Power Ascension Activities

The inspectors examined selected TSs, license conditions, and license commitments and verified that administrative prerequisites were being met prior to Unit 3 mode changes. The inspectors also reviewed measured RCS identified and unidentified leakage tests, and verified that containment integrity was properly established. The inspectors witnessed portions of the reactor startup, heatup, and power ascension in accordance with 3-GOI-100-1A, Unit Startup and Power Operation.

Corrective Action Program

The inspectors reviewed PERs generated during the Unit 3 forced outage to verify that initiation thresholds, priorities, mode holds, and significance levels were assigned as required. Resolution and implementation of corrective actions of several PERs were also reviewed for completeness.

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 two risk-significant and/or safety-related systems listed below to verify that the tests met TS surveillance requirements, UFSAR commitments, and in-service testing (IST) and licensee procedure requirements. The inspectors' review confirmed whether the testing effectively demonstrated that the SSCs were operationally capable of performing their intended safety functions and fulfilled the intent of the associated surveillance requirement. Applicable 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.

- 0-SR-3.8.1.1(BR), Diesel Generator B Operability Test (App R)
- 2-SI-4.5.C.(3), RHRSW Pump and Header Operability and Flow Test*

*This procedure included inservice testing requirements.

b. Findings

No findings of significance were identified

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 temporary modifications listed below to ensure that procedure and regulatory requirements were met. The inspectors reviewed the associated 10 CFR 50.59 screening and evaluation, and applicable system design bases documentation. The inspectors reviewed selected completed work activities and walked down portions of the systems to verify that installation was consistent with the modification documents and Temporary Alteration Control Form (TACF).

- TACF 2-05-013-085, Temporary leak repair of 0.5 inch copper elbow joint between valve 2-FCV-085-0082A and valve 2-TV–0791

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

On October 5 and December 12, 2005, the inspectors observed two simulator-based training evolutions that TVA had identified as contributing to their Emergency Preparedness (EP) Performance Indicator statistics. During these training evolutions, one of which was part of a routine quarterly onsite EP drill, and the other as part of regular LOR, the inspectors assessed operator performance to determine if emergency classification, notification, and protective action recommendations were made in accordance with emergency plan implementing procedures. The inspectors also attended and evaluated the adequacy of the critiques conducted after the training.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification & Resolution of Problems

.1 Routine Review of Problem Evaluation Reports

a. Inspection Scope

The inspectors performed a daily screening of all PERs entered into the licensee's corrective action program. The inspectors followed NRC Inspection Procedure 71152, "Identification and Resolution of Problems," in order to help identify repetitive equipment failures or specific human performance issues for follow-up.

b. Findings and Observations

There were no specific findings identified from this overall review of the PERs issued each day.

.2 Semiannual Trend Review

a. Inspection Scope

As required by Inspection Procedure 71152, the inspectors performed a review of the licensee's corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review included the results from daily screening of individual PERs (see Section 4OA2.1 above), licensee quarterly trend reports and trending efforts, and independent searches of the PER database. The inspectors' review nominally considered the six-month period of July 2005 through December 2005, although some PER database searches expanded beyond these dates. Furthermore, the inspectors verified whether adverse or negative trends and issues identified in the licensee's PERs, quarterly reports and trending efforts were entered into the corrective action program (CAP).

b. Findings and Observations

No violations of NRC requirements were identified. Due to an increasing trend in NRC non-cited violations (NCVs), the licensee performed an extensive apparent cause of these NCVs and concluded that half the NCVs were due to human performance issues. Based on this result, they expanded the analysis to included some INPO weaknesses from their last three assessments and other PERs for which human performance was coded as a cause. They determined that they did have an adverse trend. Two areas stood out; these were categorized as Misjudgement and Unawareness (lack of attention to detail). There were specific human performance improvement techniques established for each of these areas and management has emphasized them regularly. However, they have recognized that these elements from their 'human performance tool box' have not achieved the results desired. Corrective actions for improvement in these areas are currently being developed. However, based on recent events, and inspector-identified findings and observations, the inspectors have concluded that a specific aspect of the aforementioned human performance adverse trend involves Operations' use and knowledge of critical procedures which was not specifically identified by the licensee's trend evaluation. The inspectors discussed this aspect with licensee management who agreed that past operator performance regarding procedure implementation did not meet management expectations and that more focused shift Operations improvement measures were warranted.

.3 Focused Annual Sample Review

Failure of 2A RHRSW Heat Exchanger Outlet Flow Control Valve to Open

a. Inspection Scope

The inspectors reviewed PERs 63657, 91307, and 91267 and work documents, 04-717946-000, 05-721660-000, and 05-722517-000 associated with the failure of the 0-FCV-023-0034, 2A RHRSW Heat Exchanger outlet flow control valve to open when the A2 RHRSW pump was in operation. The inspectors assessed licensee actions to verify that timely and appropriate actions were taken to identify and correct the recurring problem. The applicable 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 adequate 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.

b. Findings and Observations

RHR Service Water Valve 02-FCV-023-34, 2A RHRSW Heat Exchanger Outlet Flow Control Valve has an open permissive that requires either the A1 or A2 RHRSW pump to be in operation. This permissive is accomplished by auxiliary switches (52STA) which are located in each of the pump breaker cubicles. These switches mechanically operate when the associated breaker opens and closes. Failure of the switch to operate and permit its associated flow control valve to open, blocks service water flow through the associated RHR Heat Exchanger.

On 6/21/2004, WO 04-717946-000 was written by control room personnel that 02-FCV-023-34 failed to open during surveillance 2-SI-4.5.C.1(3-COMP) with RHRSW pump A2 in operation. Electrical maintenance personnel performing the work activities found that the 52STA switch actuator arm set screw was loose on the supply breaker to A2 RHRSW pump. Following the work activity, maintenance personnel wrote PER 63657 for which the associated breaker PM procedures were revised to add an inspection for adequate tightness.

On 9/30/2005, with RHRSW pump A2 in operation, 02-FCV-023-34 failed to open again, and WO 05-721660-000 was written but subsequently cancelled when the problem would not repeat. No PER was written.

On 10/17/2005, with RHRSW pump A2 in operation, 02-FCV-023-34 failed again to open. WO 05-722427-000 was written and cancelled to WO 05-722517-000 on 10/21/2005. Also, on that date, PER 91307 was written and an LCO was entered.

The inspectors followed the troubleshooting activities associated with this last work order. Initial readings taken on the 52STA switch for the A2 RHRSW pump breaker indicated no problems with contact 6-6T which is the permissive contact on the switch, with the breaker both in the open and closed position. However, contact 10-10T did not indicate closed when it was actually closed. Hence, further troubleshooting activities were performed. The 52STA switch is mounted in the breaker cubical and is actuated by linkages which were installed as part of a modification to allow the Siemens Vacuum breaker to communicate its position to the 52STA switch. The linkage arm has a tolerance of 14 and13/32 inches plus or minus 1/32 inch from its resting position inside the cubical. The breaker was racked out and removed to measure the height position of the 52STA switch actuating arm.

The actuating arm was found to be within tolerance. Troubleshooting then required the switch to be removed. After the removal, the inspectors observed the switch operation by hand. It was apparent that the contacts did not all open and close within the same arc of rotation. New switch contacts open and close within a smaller arc of rotation. Hence, between the tight tolerance of linkage height adjustment and the gradually increasing arc of rotation required to actuate of all the contacts, these breaker-cubical pairs are very sensitive to both wear and adjustments.

The consequences of these switch failures vary by application. They perform indication functions, interlock functions, permissive functions and auto-start functions. In this particular case, the failure of this switch is only consequential from a safety perspective, if the A1 RHRSW pump was unavailable, which it was not; or if it should constitute a common cause failure.

The inspectors reviewed PER 91627 corrective actions to date. Completed corrective actions included the replacement of the switch. Planned actions included initiating work orders as necessary to ensure that like components do not have similar problems and to perform a detailed apparent cause evaluation of the failure of the A2 RHRSW pump breaker. Based upon the “apparent cause” results, other actions may be performed.

The inspectors noted that the problem with the 52STA switch has existed for some period of time, and even though the licensee’s response to this recurring problem has not completely resolved the issue, they are continuing to pursue it. The licensee’s actions to date and planned are reasonable and consistent with the level of safety significance of this breaker.

4OA3 Event Follow-up

Unit 3 Reactor Trip

a. Inspection Scope

On October 31, 2005, the Unit 3 reactor scrammed from 100% power due to loss of load caused by an apparent turbine overspeed. The inspectors responded to the site, and discussed the preliminary cause of the scram with licensee management, and Operations, Engineering, and Maintenance personnel. The inspectors also examined unit parameters and equipment response to verify that operator performance was appropriate, and safety systems responded to the scram as designed. The sensed main turbine overspeed condition occurred as a direct result of the electrical transient initiated when operators closed the 500-kV Trinity II switchyard breaker while grounding devices were still installed at a remote sub-station as part of some offsite work activities. Work activities associated with the grounding devices and switching orders were controlled by offsite PSO personnel. Human performance aspects are addressed in Section 1R14.1. The inspectors also reviewed the initial licensee event notification to verify that it met regulatory requirements.

b. Findings

No findings of significance were identified during the initial event followup. However, the inspectors are still following up on the licensee's root cause determination and corrective actions which will be addressed as an integral part of the pending LER closeout.

4OA6 Management Meetings

Exit Meeting Summary

On January 10, 2006, the resident inspectors presented the integrated inspection results to the Site Vice President, Mr. Brian O'Grady and other members of his staff, who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection period.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION
PARTIAL LIST OF PERSONS CONTACTED

Licensee

B. Aukland, Nuclear Plant Manager
W. Crouch, Nuclear Site Licensing & Industry Affairs Manager
R. DeLong, Site Engineering Manager
A. Elms, Nuclear Plant Operations Manager
A. Feltman, Emergency Preparedness Supervisor
A. Fletcher, Field Maintenance Superintendent
R. Jones, General Manager of Site Operations
J. Kennedy, Human Performance Improvement Manager
R. Kerwin, Acting Site Nuclear Assurance Manager
R. Marks, Site Support Manager
R. Marsh, Operations Superintendent
D. Matherly, Nuclear Outage and Scheduling Manager
C. Sherman, Radiation Protection Manager
J. Mitchell, Site Security Manager
D. Nye, Maintenance & Modifications Manager
B. O'Grady, Site Vice President
C. Ottenfeld, Chemistry Manager
D. Sanchez, Training Manager
E. Scillian, Operations Training Manager
J. Steele, Daily Scheduling Manager
K. Welch, Systems Engineering Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000259, 260, 296/2005005-01	FIN	Requalification Program Simulator Exam Grading Error Resulted In Unidentified Individual Failure (Section 1R11)
05000296/2005005-02	NCV	Failure to Follow Procedure in Response to Automatic Rod Blocks (Section 1R14)