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

January 30, 2007

Tennessee Valley Authority
ATTN: Mr. Karl 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 05000259/2006005, 05000260/2006005, 05000296/2006005, AND 0720052/2006002

Dear Mr. Singer:

On December 31, 2006, the United States 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 9, 2006, with Mr. Bruce Aukland and on January 29, 2007, with Mr. Brian O'Grady and other members of your staff.

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

Additionally, the enclosed report also documents some inspection of Unit 1 that was performed per our letter to you on December 29, 2004, regarding the transition of Unit 1 into the Reactor Oversight Program (ROP). In that letter we indicated that the NRC had determined that the ROP cornerstones of Occupational Radiation Safety, Public Radiation Safety, Emergency Preparedness, and Physical Protection would be incorporated into the routine ROP baseline inspection program effective January 1, 2005. The principal results from our inspection of your Unit 1 Recovery Project continue to be documented in a separate Unit 1 integrated inspection report.

This report documents an NRC-identified finding which was determined to involve a violation of NRC requirements. However, because this finding was of very low safety significance and 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 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 United States 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, its enclosure and your response, if any, 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/

Malcolm T. Widmann, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket Nos.: 50-259, 50-260, 50-296, 72-052
License Nos.: DPR-33, DPR-52, DPR-68

Enclosure: Inspection Report 05000259/2006005, 05000260/2006005, 05000296/2006005, and 0720052/2006002 w/Attachment: Supplemental Information

cc w/encl.: (See page 3)

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure and your response, if any, 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/

Malcolm T. Widmann, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket Nos.: 50-259, 50-260, 50-296, 72-052
License Nos.: DPR-33, DPR-52, DPR-68

Enclosure: Inspection Report 05000259/2006005, 05000260/2006005, 05000296/2006005, and 0720052/2006002 w/Attachment: Supplemental Information

cc w/encl.: (See page 3)

X PUBLICLY AVAILABLE ☐ NON-PUBLICLY AVAILABLE ☐ SENSITIVE X NON-SENSITIVE

ADAMS: X Yes ACCESSION NUMBER: ML070300706

OFFICE	RII:DRP	RII:DRP	RII:DRP	RII:DRS	RII:DRS	RII:DRS	RII:DRP
SIGNATURE	TMR /RA/	RLM per telecon	TXN /RA/	FJE /RA/	LXC /RA/	WTL /RA/	RS /RA/
NAME	TRoss	RMonk	TNazario	FEhrhardt	LCain	WLoo	RSchin
DATE	01/30/2007	01/30/2007	01/30/2007	01/30/2007	01/30/2007	01/30/2007	01/30/2007
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICE	RI:DRP	RII:DRP	RII:DRP				
SIGNATURE	TMR for	LXG /RA/	MTW /RA/				
NAME	MMorris	LGarner	MWidmann				
DATE	01/30/2007	01/30/2007	01/30/2007				
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICIAL RECORD COPY DOCUMENT NAME: C:\FileNet\ML070300706.wpd

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

Preston D. Swafford
Senior Vice President
Nuclear Support
Tennessee Valley Authority
Electronic Mail Distribution

General Counsel
Tennessee Valley Authority
Electronic Mail Distribution

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

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

Robert H. Bryan, Jr., General Manager
Licensing & 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

Beth A. Wetzel, Manager
Corporate Nuclear Licensing and
Industry Affairs
Tennessee Valley Authority
4X Blue Ridge
1101 Market Street
Chattanooga, TN 37402-2801

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)

Letter to Karl W. Singer from Malcolm T. Widmann dated January 30, 2007.

SUBJECT: BROWNS FERRY NUCLEAR PLANT - INTEGRATED INSPECTION REPORT 05000259/2006005, 05000260/2006005, 05000296/2006005, and 0720052/2006002

Distribution w/encl.:
J. Boska, NRR
E. Brown, NRR
L. Raghavan, NRR
C. Evans, RII
L. Slack, RII EICS
L. Mellen, RII
OE Mail
RIDSNRRDIRS
PUBLIC

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.:	05000259/2006005, 05000260/2006005, 05000296/2006005, and 0720052/2006002
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 - December 31, 2006
Inspectors:	T. Ross, Senior Resident Inspector R. Monk, Resident Inspector L. Cain, Senior Reactor Inspector (Section 1R21) F. Ehrhardt, Operator Licensing Examiner (Section 1R11.2) W. Loo, Senior Health Physicist (Section 4OA5.1) M. Morris, Senior Resident Inspector T. Nazario, Project Engineer R. Schin, Senior Reactor Inspector (Section 1R21)
Approved by:	Malcolm T. Widmann, Chief Reactor Project Branch 6 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000259/2006005, 05000260/2006005, 05000296/2006005, 07200052/2006002; 07/01/2006 - 09/30/2006; Browns Ferry Nuclear Plant, Units 1, 2, and 3; Safety System Design and Performance Capability

The report covered a three-month period of routine inspections by the resident inspectors; a senior resident inspector from another site; and, a senior operations examiner, two senior reactor inspectors, a senior health physicist and a project engineer from Region II. One Green non-cited violation was identified. The significance of most findings are indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or assigned a severity level after NRC management review. 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: Mitigating Systems

- Green. The inspectors identified a non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion III, Design Control, that affected Units 2 and 3. The licensee's calculations and procedures did not adequately implement the plant's licensing basis for Station Blackout (SBO), in that, they did not ensure the operating emergency diesel generators (EDGs) would have an adequate cooling water supply during a SBO with certain plant equipment configurations.

  This finding is of greater than minor safety significance because it affected the objectives of the Mitigating Systems Cornerstone. It affected the availability and reliability of systems that mitigate initiating events to prevent undesirable consequences. The finding has very low safety significance due to the few very specific combinations of EDG failures that could lead to a loss of cooling water flow to all of the running EDGs. The licensee took prompt corrective action by revising procedures to add immediate operator actions to ensure adequate cooling water supply to the EDGs. (Section 1R21)

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status

Unit 1 was defueled and in a recovery status until December 15, 2006, when refueling operations commenced and the unit entered Mode 5. On December 22, core reload of Unit 1 was completed. The unit remained in Mode 5 for the rest of the report period.

Unit 2 operated at essentially full power for the entire report period, except for a planned shutdown and cooldown on October 10 to install strain gauges on the main steam (MS) lines. The unit was restarted on October 21 and reached full power on October 23.

Unit 3 operated at essentially full power for the entire report period, except for a planned downpower to 50% and a planned shutdown. On December 2, Unit 3 power was reduced to approximately 50% to repair the main bus duct cooling fan and other secondary side equipment. The unit was returned to full power on December 4. On December 8, Unit 3 power was reduced to 15% to investigate a five gallons per minute (gpm) step increase in reactor coolant system (RCS) identified leakage. The unit was subsequently shutdown the next day to repair a reactor building closed cooling water (RBCCW) leak from the 3B reactor recirculation pump motor cooler. Unit 3 was restarted on December 11, and full power achieved on December 12.

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, including associated attachments, and examined licensee actions to implement this procedure in preparation for cold weather conditions. The inspectors also reviewed the list of open work orders (WOs) and Problem Evaluation Reports (PERs) to verify that the licensee was identifying, prioritizing, correcting, and as necessary implementing compensatory measures, for problems relating to cold weather operations. Furthermore, the inspectors walked down selected risk significant systems and areas of the plant, specifically the residual heat removal service water (RHRSW) and Emergency Equipment Cooling Water (EECW) systems, and Condensate Storage and Supply (CS&S) system, to verify that potentially affected systems and components were properly configured and protected against freezing temperatures.

The inspectors discussed cold weather conditions with Operations personnel to assess plant equipment conditions and personnel sensitivity to upcoming cold weather conditions. The inspectors also conducted several walkdowns of the main control rooms to assess system performance and alarm conditions of systems susceptible to cold weather conditions. Furthermore, during the initial two weeks of November, when outside temperatures dropped below the 32 degree Fahrenheit (°F) and 25°F thresholds on several occasions, the inspectors verified that the applicable equipment walkdown checklists of 0-GOI-200-1 were implemented accordingly. The inspectors also toured exposed equipment and systems during sub-freezing conditions.

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 safety systems listed below to verify train operability, as required by the plant Technical Specifications (TS), while the other redundant trains were out of service or after the specific safety system was returned to service following maintenance. These inspections included reviews of applicable TS, operating instructions (OI), 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 Loop I Core Spray (CS) system per PI&D flow diagrams 2-47E814-1 and 2-OI-75 while Loop II was being tested
- Unit 3 High Pressure Coolant Injection (HPCI) system per PI&D flow diagrams 3-47E812-1 and 3-OI-73 while the Reactor Core Isolation Cooling (RCIC) system was being tested
- Unit 3 Loop I Residual Heat Removal (RHR) system per PI&D flow diagrams 0-47E811 and 3-OI-74 following flushing activities
- Unit 2 RHR Loop II per PI&D flow diagrams 2-47E811-1 and 2-OI-74 while Loop I was being tested

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Routine Walkdowns

a. Inspection Scope

Walkdowns. The inspectors reviewed licensee procedures, Standard Programs and Processes (SPP)-10.10, Control of Transient Combustibles, and SPP-10.9, Control of Fire Protection Impairments, and conducted a walkdown of the fire areas (FA) and fire zones (FZ) 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 features 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, 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.

- Unit 3 Reactor Building El. 593 (Fire Zone 3-3)
- Unit 1 Battery and Battery Board Rooms (Fire Area 17)
- Unit 2 Battery and Battery Board Room (Fire Area 18)
- Radwaste Building (Fire Area-25)
- Control Building - Elevation 606' (FA-16)
- Control Building - Elevation 617' (FA-16)
- Unit 2 Reactor Building Elevation 593' (FA-16)

b. Findings

No findings of significance were identified.

.2 Annual Fire Brigade Drill

On November 2, the inspectors witnessed an unannounced fire drill in the west cable spreading room for Units 1 and 2. The inspectors assessed fire alarm effectiveness; response time for notifying and assembling the fire brigade; the selection, placement, and use of fire fighting equipment; use of personnel fire protective clothing and equipment (e.g., turnout gear, self-contained breathing apparatus); communications; incident command and control; teamwork; and fire fighting strategies. The inspectors also attended the post-drill critique to assess the licensee's ability to review fire brigade performance and identify areas for improvement. Following the critique, the inspectors compared their findings with the licensee's observations and to the requirements specified in the licensee's fire protection report.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors performed a review of the Unit 2 and 3 RHR and CS pump rooms, Under-Torus area, and the Intake Structure, for internal flood protection measures. The inspectors reviewed plant design features and measures intended to protect the plant and its safety-related equipment from internal flooding events, as described in the following documents: Updated Final Safety Analysis Report (UFSAR); Design Criteria BFN-50-C-7105, Internal Flooding Design Basis; Emergency Operating Instruction (EOI) - 3, Secondary Containment Control; and, Browns Ferry Unit 2 Individual Plant Examination, Browns Ferry Internal Floods Analysis. Furthermore, the inspectors reviewed the Browns Ferry Nuclear Plant Probabilistic Safety Assessment Initiating Event Notebook, Initiating Event Frequencies, for licensee commitments.

The inspectors performed walkdowns of risk-significant areas, susceptible systems and equipment, including the Unit 2 and 3 RHR, CS pump rooms, HPCI pump room, Under-torus area and the RHRSW Intake Structure to review flood-significant features such as flood protection door seals, conduit seals and instrument racks that might be subjected to flood conditions. Plant procedures for mitigating flooding events were also reviewed to verify that licensee actions were consistent with the plant's design basis assumptions.

The inspectors also reviewed a sampling of the licensee's corrective action documents with respect to flood-related items to verify that problems were being identified and corrected. Furthermore, the inspectors reviewed selected completed preventive maintenance procedures, work orders, and surveillance procedures to verify that actions were completed within the specified frequency and in accordance with design basis documents.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program

.1 Requalification Activities Review

a. Inspection Scope

On November 14, 2006, the inspectors observed dual-unit simulator training for two crews, utilizing the Unit 2 and 3 simulators simultaneously. This training scenario involved a Loss of Offsite Power (LOOP) event on both simulators followed by a Loss of Coolant Accident (LOCA) on the Unit 3 simulator. The simulator scenario used for both crews was challenging, and involved critical equipment failures, abnormal operational transients and accident conditions.

The inspectors 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), EOIs, and Operational Contingencies
- Timely and appropriate Emergency Action Level declarations per Emergency Plan Implementing Procedures (EPIP)
- Control board operation and manipulation, including high-risk operator actions
- Command and Control provided by the Unit Supervisor and Shift Manager

The inspectors also attended the subsequent performance critique of both crews to assess the effectiveness of the licensee training evaluators, and to verify that licensee-identified issues were comparable to issues identified by the inspector.

b. Findings

No findings of significance were identified.

.2 Annual review of Licensee Requalification Examination Results.

a. Inspection Scope

On October 13, 2006, the licensee completed the requalification annual operating tests, required to be given to all licensed operators by 10 CFR 55.59(a)(2). The inspectors performed an in-office review of the overall pass/fail results of the individual operating tests and the crew simulator operating tests. These results were compared to the thresholds established in Manual Chapter 609 Appendix I, Operator Requalification Human Performance Significance Determination Process.

b. Findings

No findings of significance were identified.

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 (a)(1) goals and corrective actions (i.e., Ten Point Plan). Both of these systems had exceeded their reliability performance criteria and were 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; and SPP 3.1, Corrective Action Program. The inspectors also reviewed applicable work orders, surveillance records, PERs, system health reports, engineering evaluations, and MR expert panel minutes; and attended MR expert panel meetings to verify that regulatory and procedural requirements were met.

- RHRSW outlet valves for RHR Heat Exchangers
- 1B 480V Reactor Motor-Operated Valve (RMOV) Board Normal Supply Breaker

b. Findings

No findings of significance were identified

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

For planned online work and/or emergent work that affected the risk significant systems as listed below, the inspectors reviewed licensee maintenance risk assessments and actions taken to plan and control work activities to effectively manage and minimize risk. The inspectors verified that risk assessments and risk management actions (RMA) were being conducted as required by 10 CFR 50.65(a)(4) and applicable procedures such as SPP-6.1, Work Order Process Initiation, SPP-7.1, Work Control Process and 0-TI-367, BFN Dual Unit Maintenance Matrix. The inspectors also evaluated the adequacy of the licensee's risk assessments and the implementation of RMAs.

- 3C Emergency Diesel Generator (EDG), and Standby Liquid Control (SLC) System out of service (OOS)
- 1B Control Rod Drive (CRD) Pump, 2B RHR Pump and Hx, 2B RHRSW Pump, and Standby Cooling Mode OOS
- Unit 2 both trains of SLC System OOS
- 1B CRD Pump and 2C RHR Pump and Heat Exchanger OOS
- 3A and 3C RHR pumps and Unit 2/3 RHR crosstie valve OOS
- 1B CRD Pump, 2A RHR Pump, 2A CSS Pump, A1 and A2 RHRSW Pumps, and 2D RHR Heat Exchanger OOS

b. Findings

No findings of significance were identified

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the operability/functional evaluations listed below to verify technical adequacy and ensure that the licensee had adequately assessed TS operability. The inspectors also reviewed applicable sections of the UFSAR to verify that the system or component remained available to perform its intended function. In addition, where appropriate, 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 on a daily basis to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

- 3A CRD Pump Casing Erosion (PER 111588)
- Ambient Temperature Conditions Exceed Assumption in Heating Ventilation and Cooling Calculation (PER 108745)
- Unit 2 Primary Containment Purge System Exceeding Flow Testing Surveillance Interval (PER 113450)
- 3B Reactor Feedwater Pump Turbine High Pressure Stop Valve failing to fully close (PER 112657)
- Inadequate EECW Supply for EDGs During the Limiting Station Blackout Event Event (PER 114913 and 114967)

b. Findings

No findings of significance were identified.

IR17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed the Design Change Notice (DCN) and completed work package for DCN 64473, Replace Unit 2 Unit Preferred MMG Set AC Drive Motor Feeder Breaker and Trip Device, including related documents and procedures. The inspectors also observed the following activities: breaker testing pre-job brief; breaker testing per trouble-shooting plan, WO 06-722293-001; field installation; and post maintenance testing.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the post-maintenance tests (PMT) listed below to verify that procedures and test activities confirmed system, structure, or component (SSC) operability and functional capability following maintenance. The inspectors reviewed the licensee's completed test procedures to ensure any of the SSC safety function(s) that may have been affected were adequately tested, that the acceptance criteria were consistent with information in the applicable licensing basis and/or design basis documents, and that the procedure had been properly reviewed and approved. The inspectors also witnessed the test and/or reviewed the test data, to verify that test results adequately demonstrated restoration of the affected safety function(s). The inspectors also verified that PMT activities were conducted in accordance with applicable work order (WO) instructions, or procedural requirements, including SPP-6.3, Post-Maintenance Testing, and MMDP-1, Maintenance Management System. Furthermore, the inspectors reviewed problems associated with PMTs that were identified and entered into the CAP.

- Unit 3: PMT for 3B Right Bank EDG Starting Air Compressor per WO 06-722929-000
- Unit 2: PMT for 2C Inboard Main Steam Isolation Valve (MSIV) per 2–SR-3.6.1.3.10C), Primary Containment Local Leak Rate Test Main Steam Line C: Penetration X-7C
- Unit 3: PMT for H202 Torus Inboard Sample Valve 3FSV-076-0057 per 3-SR-3.6.1.3.5(76 I), H202 System Isolation Valve Operability Test (Division I)
- Unit 2: PMT for 2C RHR Heat Exchanger per 2-SR-3.5.1.6 (RHR1), Quarterly RHR System Rated Flow Test Loop I
- Unit 2: PMT for EDG B per 0-TI-533, Diesel Generator B Emergency Unit 1 Load Acceptance Test
- Unit 2: PMT for 1B CRD Pump (Backup for 2A CRD pump) per PMT-0-000-MEC001, Leak Checks on Tube Fittings, Threaded, Flanged or Bolted Connections

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

.1 Unit 2 Planned Shutdown for Steam Line Instumentation Installation

a. Inspection Scope

On October 10 - 21, 2006, the inspectors examined critical activities associated with a planned shutdown of Unit 2 to install monitoring devices (e.g., strain gauges), on the

Main Steam Lines for purposes of data collection. Some of the more significant outage activities monitored, examined and/or reviewed by the inspectors were as follows:

- Unit down power, manual reactor scram, and cooldown in accordance with 2-GOI-100-12A, Unit Shutdown from Power Operation to Cold Shutdown ... , and 2-AOI-100-1, Reactor Scram
- Shutdown cooling system initiation and extended Mode 4 operations
- Outage risk assessment
- Emergent work activities and problem solving (e.g., 2C MSIV excessive leakage and subsequent repair)
- Restart Plant Oversight Review Committee
- Unit power ascension in accordance with 2-GOI-100-1A, Unit Startup and Power Operation.

The inspectors also verified that selected TS, license conditions, license commitments, and administrative prerequisites were being met prior to Unit 2 mode changes. Furthermore, the inspectors verified the conduct of reactor coolant system (RCS) identified and unidentified leakage tests.

Containment Closeout

On October 18, 19, and 21, the inspectors conducted detailed closeout inspections of all levels the Unit 2 drywell prior to plant startup, and examined licensee implementation of 2-GOI-200-2, Drywell Closeout.

Corrective Action Program

The inspectors reviewed PERs generated during the Unit 2 outage to verify that initiation thresholds, priorities, mode holds, and significance levels were assigned as required. Certain aspects of the resolution and implementation of corrective actions of several PERs were also examined and/or verified.

b. Findings

No findings of significance were identified.

.2 Unit 3 Forced Outage Due To Excessive Drywell Leakage

a. Inspection Scope

On December 8 - 10, 2006, the inspectors examined critical activities associated with the Unit 3 unplanned shutdown to verify that they were conducted in accordance with TS, applicable procedures, and the licensee's outage risk assessment and management plans. Some of the more significant outage activities monitored, examined and/or reviewed by the inspectors were as follows:

- Unit downpower in accordance with 3-GOI-100-12A
- Control of Hot Shutdown (i.e., Mode 3) conditions, and critical plant parameters

- Outage risk assessment and management
- Control and management of forced outage and emergent work activities
- Reactor Startup and Power Ascension activities in accordance with 3-GOI-100-1A

The inspectors also verified that selected TS, license conditions, license commitments, and administrative prerequisites were being met prior to Unit 3 mode changes. Furthermore, the inspectors verified the conduct of RCS identified and unidentified leakage tests.

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. Certain aspects of the resolution and implementation of corrective actions of several PERs were also examined and/or verified.

b. Findings

No findings of significance were identified.

1R21 Safety System Design and Performance Capability

Station Blackout Mitigation

a. Inspection Scope

In preparation for the planned restart of Unit 1 and three unit operation, the inspectors reviewed the licensee’s compliance with the Station Blackout Rule (10 CFR 50.63, Loss of All AC Power), as described in the NRC Supplemental Safety Evaluation (SSE) titled “Station Blackout - Browns Ferry Units 1, 2, and 3,” dated September 16, 1992. The inspection included a review of the licensee’s ability to accomplish an integrated safe shutdown of all three units as described in the Supplemental Safety Evaluation. The scope of the inspection is discussed in more detail in Unit 1 inspection report 05000259/2006009.

b. Findings

Lack of Assured Cooling Water for Emergency Diesel Generators (EDGs)

Introduction. The inspectors identified a Green non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion III, “Design Control,” that affected Units 2 and 3. The licensee’s calculations and procedures did not adequately implement the licensing basis for Station Blackout (SBO), in that, they did not ensure that operating EDGs would have sufficient cooling water flow under certain equipment configurations during a SBO. This finding also affected Unit 1 and is discussed in the Unit 1 inspection report 05000259/2006-009.

Description. The Browns Ferry licensing basis for SBO reflects three unit operation. As described in the SSE and in the Updated Final Safety Evaluation Report (UFSAR), the site must be able to cope for four hours with an SBO on one unit and a loss of offsite power (LOOP) on the other two units using only three of the eight onsite EDGs. However, only four of the eight EDGs will automatically provide power to an EECW pump. The licensee's UFSAR and SBO analysis stated that two EECW pumps are required to provide adequate cooling for the EDGs. If necessary, the licensee's engineers calculated that the EDGs could operate lightly loaded during the beginning of an SBO event with only one EECW pump providing cooling flow. However, there are some combinations where three EDGs could be operating in response to a SBO that would not result in power being automatically provided to any EECW pumps. Licensee analysis found that a heavily loaded EDG with no cooling water would overheat in about five minutes. Similarly, the licensee's analysis determined that a lightly loaded EDG with no cooling water would overheat in about 15 to 20 minutes.

The inspectors reviewed calculation MD-Q099-920053, "Station Blackout - Multi-Unit HVAC and DG Availability Analysis," Rev. 8, and abnormal operating instruction (AOI) 0-AOI-57-1A, "Loss of Offsite Power (161 and 500 KV)/Station Blackout," Rev. 64. The inspectors found that the calculation, which described the SBO mitigation strategy, and the AOI were applicable to all three units. However, these documents possessed several shortcomings. They did not identify the need for urgent (i.e., time critical) operator action to ensure EECW flow to the EDGs. They did not evaluate how long the EDGs could operate without cooling water flow (the EDGs had no automatic over-temperature protection so operator action would be necessary to prevent diesel failure). And they did not evaluate how long it would take operators to perform other non-proceduralized but potentially urgent operator contingency actions.

The inspectors found that the abnormal procedure did not include immediate operator actions to ensure that operating EDGs would have adequate cooling water during a LOOP to prevent them from overheating. While not proceduralized, the licensee noted that two of the swing RHRSW/EECW pumps had a discharge motor-operated valve (MOV) that, if opened from the main control room, would quickly direct flow to the EECW system and cool the operating EDGs. However, the inspectors found that the electrical power supply for the MOV was provided by an EDG different than the one that powered the corresponding pump. Thus, the valve could possibly be without power requiring an operator outside the main control room to remotely open the valve. Power could be realigned to the valve from the main control room but these actions were not included in the AOI.

Specifically, EDG B powered swing RHRSW/EECW pump C-1 for which normal power to crosstie MOV FCV-67-49 was provided by 480V DG Aux Board A. This electrical board is normally powered from EDG A. Alternately, this board can be powered from EDG B by operator actions in the main control rooms but these time critical actions were not directed by the operating procedures. A similar situation existed for EDG 3D which powered swing RHRSW/EECW pump D-1, and crosstie MOV FCV-67-48 which was powered by DG Aux Board B. The inspectors noted that the ability for the operators to quickly realign a swing RHRSW/EECW pump from the control room to provide EECW flow to the EDGs was credited in the SDP Reactor Workbook for a LOOP on Unit 2 or 3. Thus, the identified inability of operators to promptly restore EECW from the main control room in accordance with plant procedures represented a risk-important condition.

The licensee entered this issue into their corrective action program in PERs 114913 and 114967. Abnormal procedure 0-AOI-57-1A was revised to include immediate operator actions to ensure cooling water is provided to all operating EDGs. These actions consisted of re-energizing buses as necessary through available electrical crossties.

Analysis. Having a plant design and procedures that did not ensure adequate and timely cooling water supply to the EDGs during an SBO event is a performance deficiency. It affected the Mitigating Systems cornerstone objective to ensure the availability and reliability of systems that mitigate initiating events to prevent undesirable consequences in that the licensee failed to implement adequate design control for SBO. The SDP Phase 1 analysis did not screen to Green, consequently an SDP Phase 2 analysis was required. With no credit for operators quickly realigning a swing RHRSW/EECW from the main control room, the Phase 2 analysis for a LOOP event did not screen to Green. Pursuant to MC 0609A, a Phase 3 risk analysis was performed by a regional Senior Reactor Analyst.

Input from the NRC's plant-specific risk model and manual calculations to represent the likelihood of the specific combinations of EDGs that represent the finding were used in a manual risk calculation. Because the sequences involved SBO scenarios, the Large Early Release Frequency (LERF) metric was used. The developed sequences involved a loss of offsite power, followed by a common cause failure of either 3 or 4 EDGs. Only very specific combinations of operating EDGs will result in the loss of cooling water to all EDGs. The common cause failure rates were reduced by the ratio of those specific combinations to the total combinations for each failure of interest. The analysis assumed that one running pump would provide sufficient EDG cooling for a long enough period that some operator recovery credit was possible. However, conservatively no operator recovery credit was allowed for the condition where no cooling water pumps were aligned to the EDGs. The conditional core damage probability (CCDP) for SBO was calculated using the NRC's Standardized Plant Analysis Risk (SPAR) model for Browns Ferry 2 and 3. This CCDP was multiplied by the other factors to obtain the change in risk from the finding. The analysis resulted in a large early release frequency of less than 1E-7 per year, which is of very low safety significance. The finding has very low safety significance due to the few very specific combinations of EDG failures that could lead to a loss of cooling water flow to all of the running EDGs. No cross-cutting aspect was identified for this finding since the root cause occurred in the 1990's and is not indicative of current performance.

Enforcement. 10 CFR 50, Appendix B, Criterion III, "Design Control," requires that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. Regulatory requirements of 10 CFR 50.63, 'Loss of All AC Power," were to be implemented as described in the NRC Supplemental Safety Evaluation entitled "Station Blackout - Browns Ferry Units 1, 2, and 3," dated September 16, 1992, and in the design basis as stated in the UFSAR Section 8.10, "Station Blackout." This included the ability of the site to mitigate an SBO event on one unit and a LOOP on the other two units with only three EDGs operating in response to the event.

Contrary to the above, the regulatory requirements and design basis for SBO were not correctly translated into specifications, drawings, procedures, and instructions. Specifically, calculation MD-Q099-920053, “Station Blackout - Multi-Unit HVAC and DG Availability Analysis,” Rev. 8, and abnormal procedure 0-AOI-57-1A, “Loss of Offsite Power (161 and 500 KV)/Station Blackout,” Rev. 64, did not ensure that the site could mitigate an SBO on one unit and a LOOP on the other two units with only three EDGs in operation. The calculation and procedure did not ensure that the operating EDGs would have adequate cooling water flow to prevent them from overheating. Because this failure to ensure that regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions is of very low safety significance and has been entered into the licensee’s corrective action program in PERs 114913 and 114967, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. It is identified as NCV 05000260,296/20060005-01, “Lack of Assured Cooling Water for Emergency Diesel Generators During SBO Conditions.”

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed portions and/or reviewed completed test data for the following surveillance tests of risk-significant and/or safety-related systems 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.

- 3-SI-3.2.29, MSIV Alternate Leakage Path Testing
- 2-SR-3.5.3.3, RCIC System Rated Flow at Normal Operating Pressure
- 2-SR-3.3.1.1.5, Source Range Monitor and Intermediate Range Monitor Overlap Verification
- 3-SR-3.5.1.7, HPCI Main and Booster Pump Set Developed Head and Flow Rate Test at Rated Reactor Pressure*

* an inservice test procedure.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

Initiating Events Cornerstones

Unplanned Scrams and Transients

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the following Performance Indicators (PI), including procedure SPP-3.4, Performance Indicator for NRC Reactor Oversight Process for Compiling and Reporting PI's to the NRC. The inspectors reviewed raw PI data for the PI's listed below for the second quarter of 2004 through the third quarter of 2006. The inspectors compared the licensee's raw data against graphical representations and specific values reported to the NRC in the most recent PI report to verify that the data was correctly reflected in the report. The inspectors also reviewed the past history of PERs for any that might be relevant to problems with the PI program. Furthermore, the inspectors met with responsible plant personnel to discuss and go over licensee records to verify that the PI data was appropriately captured, calculated correctly, and discrepancies resolved. The inspectors reviewed Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, to verify that industry reporting guidelines were applied.

- Unit 2 Unplanned Scrams
- Unit 3 Unplanned Scrams
- Unit 2 Unplanned Scrams with loss of heat sink
- Unit 3 Unplanned Scrams with loss of heat sink
- Unit 2 Unplanned Transients
- Unit 3 Unplanned Transients

b. Findings

No findings of significance were identified.

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 and WO history. The inspectors' review nominally considered the six-month period of July 2006 through December 2006, although some PER database and WO 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 CAP.

b. Findings and Observations

Trend reviews by the licensee were performed quarterly on a departmental basis. One of the objectives of the trend review was to identify top organizational issues and to status the progress in resolving them. Although two of the departments (Maintenance and Outage & Scheduling) have different top issues, these issues appear to have a common thread related to emergent equipment issues, even though they may at times manifest themselves as resource and schedule adherence issues. Furthermore, equipment issues contributed directly to transient challenges for the Operations Department, dose management challenges for Radiation Protection Department and resource management challenges for the Engineering Department. Continued problems with equipment reliability issues were found in each of the individual department trend reports. Current efforts by the licensee for equipment improvement were focused on management of broad performance indicators such as reducing the work order backlog, minimizing deferred preventative maintenance, etc. Other than as described above, no significant trends were noted by any of the other departments.

Additional inspector follow-up of some specific equipment issues indicated that corrective actions were not prioritized in a manner to yield the most efficient resolution of the problem. Problem Evaluation Report 104621 dated June 8, 2006 and PER 75912 dated February 1, 2005 were examples.

The equipment problem identified by PER 104621 involved multiple failures of the RHRSW side outlet valves of the RHR heat exchangers. Based on the results of the associated root cause analysis, these valves are suffering failures due to flow induced vibration. The most recent, of a long history of vibration related failures, has manifested itself as broken wires in the motor terminations. In addition to vibration, the licensee believes a severe radius bend of the motor terminations may also be a contributing cause of the failures. The licensee's PER corrective actions included inspection for radius bend issues on the family of valves (which includes 12 valves) and vibration data collection. Since the motor termination inspections require the associated RHR loop to be made inoperable, these inspections have been scheduled over a number of months with the last one to be completed in January of 2007. However, the acquisition of vibration data which is probably the principal cause does not require any system inoperability, but for no apparent reason was scheduled for February 2007 following the termination inspection. During routine quarterly flow testing, each of the RHRSW outlet valves have flow put through them with an attendant opportunity to take vibration data. The last RHRSW outlet valve failure was in March of 2006, and per the licensee's schedule it will be almost a year before it is determined if all valves have similar vibration problems, or which valves have the most severe problem, and which valves need the highest priority of follow on corrective actions. Currently, all follow on corrective actions were awaiting the completion of the data collection in February 2007, which could have been accomplished much sooner.

The equipment problem identified by PER 75912 relates to the RHRSW inlet check valves to the RHR Heat Exchangers. These check valves have a chronic history of sticking open. One of the corrective actions was to scribe the check valve hinge pin so the its position could be visually verified vice the expense and difficulty of radiography. Scribing would also allow check valve position verification to be done in conjunction with quarterly flow testing and would require no system inoperability. However, the licensee did not implement the hinge pin scribing until December of 2006, due in part to poor prioritization behind other corrective actions like programmatic reviews. In the mean time, seven of eight valves where found stuck open in 2006 on Units 2 and 3, similar to the failures identified by previous PERS in 2003 to 2005. Another PER 116511 was initiated to address the most recent failures in 2006.

In both of the above examples, the licensee failed to adequately recognize the benefit of certain straightforward corrective actions that could be accomplished without incurring out of service time in order to more effectively prioritize their corrective actions to yield the greatest benefit at the soonest opportunity in terms of resolving the deficiency.

In a totally separate issue, the inspectors independently identified a potentially adverse trend. Following the Unit 2 restart from its midcycle outage (see Section 1R20.1), the inspectors identified that a nonsafety-related Unit 2 Extraction Steam Non-Return valve (2-FCV-5-1) was not tested during startup contrary to the recommendation made in the functional evaluation for PER 94495. Poor coordination between Operations and Engineering failed to highlight the need for performing this testing during startup due to valve position indication (VPI) problems that prevented the normal daily testing of 2-FCV-5-1 at power. Furthermore, the PER 94495 functional evaluation recommended repairing the 2-FCV-5-1 VPI at the earliest convenience, but TVA failed to include this repair during the most recent midcycle outage. In response to the inspectors' concerns, the licensee initiated PERs 113344 and 113577. Although the Extraction Steam Non-Return valves were not safety-related, the inadequate coordination and/or communication between Engineering and Operations/Maintenance was indicative of previous issues of a much more significant nature documented as Unresolved Items (URIs) in IR 05000260 and 296/2006-04. The failure to implement necessary compensatory measures and/or recommendations developed and documented in PER functional evaluations was considered a potential adverse trend by the inspectors based most recently on the previous IR's URIs and the issue described above. In response to this potential adverse trend, the licensee initiated PER 113572 to re-evaluate their current methods for implementing compensatory measures and/or recommendations from Engineering to ensure these actions are accomplished in a timely manner.

No violations of NRC requirements were identified.

.3 Focused Annual Sample Review

The inspectors verified licensee implementation of corrective actions associated with PERs 54941, 55116, 52861 and 55820 that were not examined by the Problem Identification and Resolution (PI&R) team inspection of 2005 (see IR 50-260 and 296/ 05-11). Two of the PERs (54941 and 52861) were associated with non-cited violations (NCVs) and the remaining two PERs (55116 and 55820) were associated with Licensee Event Reports (LERs). PER 55820 was classified as a Level A PER which required a root cause analysis in accordance with the licensee's corrective action program. The remaining PERs were classified as Level C PERs; however, after further review PER 55116 should have been categorized as a Level B. But in this case, the corrective actions associated with PER 55116 were commensurate with a Level B PER and were considered to be appropriate.

a. Inspection Scope

The inspectors reviewed the aforementioned PER's in detail, including related corrective action documents and causal analysis, to ensure that the full extent of the described issues were identified, thorough evaluations performed, and appropriate corrective actions were specified, prioritized and completed. The inspector also evaluated licensee actions against the requirements of the licensee corrective action program as specified in SPP-3.1, Corrective Action Program, and 10 CFR 50, Appendix B.

b. Findings and Observations

PER 54941

A Licensee-Identified Green NCV from Inspection Report 05000260, 296/2003003 was addressed by PER 54941. The PER discussed that the Technical Surveillance Requirement (TSR) 3.7.4.2.c of the Technical Requirements Manual (TRM) did not require verifying that the snubber stroke settings were consistent with the design drawings, and as such these verifications were not being systematically performed. The root cause of this condition was identified as being the decision to remove snubber stroke setting verification from the snubber functional test Surveillance Instructions based on the misconception the verification was being adequately performed as part of maintenance procedure MPI-000-SNB004. The inspectors verified that corrective actions including revising surveillance procedures, designating a back up snubber engineer and verifying that a sample of the work orders, had been implemented.

The inspectors also discussed the Case Specific Acceptance Criteria for snubbers with licensee personnel for 2-SNUB-074-5057 and WO-98-012561-000. The inspectors noted that both the as-found setting and the as-left setting values did not meet the acceptance screening criteria for thermal movement extension as documented in the sheet. The checkbox for tests results meeting the acceptance criteria was marked as yes and was inconsistent with the line item specified. After further review of the justification and discussions with the responsible engineer, the licensee explained that the thermal growth value based on pipe stress calculations was well below the margin noted in the acceptance criteria. The inspectors verified the pipe stress analysis data sheets and confirmed that the snubber had sufficient travel margin.

PER 55116

During a review of the Appendix R calculations associated with the restart of Browns Ferry Unit 1, the licensee noted that some associated circuits of certain 4KV electrical distribution boards and loads were not adequately evaluated in the Unit 2 and 3 calculations. Specifically, a concern was raised that a reactor building fire could cause a fault in a recirculation pump MG set supply cable and also cause a loss of the power required to trip the breaker. Cable separation is provided for these circuits so that shorts, open circuits, or shorts to ground will not prevent safe shutdown during a fire event. As a result of the discovery of this issue, the licensee took immediate compensatory measures which included fire watches for the areas identified in accordance with the BFN Fire Protection Program.

The inspectors noted, that at the time of discovery, the PER was classified as a Level C PER; however, after further review of SPP-3.1, the inspectors noted that a Level B was warranted due to LER 50-260/2003-004-00 being issued. The SPP-3.1, Appendix E, specifically states that the condition classification criteria for a Level B includes NRC reportable issues requiring a formal written response, including LER and NRC cited violations. The licensee agreed that based on current implementation of SPP-3.1, this PER should have been categorized as a Level B PER. Since the licensee performed a functional evaluation and took immediate compensatory measures, the licensee evaluated the PER in a manner commensurate with a Level B PER.

The apparent cause was associated with the circuit separation error being missed during the unit re-start Appendix R evaluation. The common vulnerabilities to damage from a single fire of the control power circuits for the recirculation pump drives on Unit 2 and motor-generator sets on Unit 3 were not properly evaluated when the Appendix R calculations were originally performed. Discussions with licensee personnel confirmed that modifications requiring fuses to be installed at the Reactor Recirculation Pump (RRP) Boards (DCN 60035 and DCN 60546) had been fully implemented.

PER 52861

During a 40-hr inboard seal replacement outage on October 14, 2003, maintenance was conducted using procedure MCI-0-085-PMP001, Control Rod Drive (CRD) Hydraulic Pump-Worthington 2 WT-810 Disassembly, Inspection, Rework and Reassembly. The 3A CRD pump failed the PMT, per WO 03-5269-000, after the new seal replacement.

This was due to inadequate procedure guidance, in that the proper clearance between the gland plate assembly and the drive collar was not specified. As a result of this issue, a self-revealing green NCV was identified and documented in Section 1R12 of inspection report (IR) 05000296/2003005-01, Inadequate Procedure for Control Rod Drive Pump 3A. The violation was associated with 10 CFR 50 Appendix B, Criterion V, Instructions, Procedures and Drawings, in that procedure MCI-0-085-PMP001 at the time of the failure did not contain the necessary guidance to correctly install a new seal. After reviewing the corrective actions associated with the PER, the inspectors noted the licensee did not fully implement all the corrective actions as detailed in the PER corrective action plan. More specifically, the licensee did not incorporate into MCI-0-085-PMP001 the required clearance measurement between the gland Plate Assembly and the drive collar, and did not include a reminder (note) that the speed increaser must be disassembled in order to facilitate use of the laser alignment equipment. However, the licensee did implement changes relating to determining the sag prior to alignment and added appropriate steps for recording data when using laser alignment.

Interviews with licensee personnel, indicated that a review of prior corrective maintenance history and work orders since the 3A CRD pump seal failure, did not reveal any operability issues or failures related to CRD pump seals. In addition, the inspectors verified that routine work orders were performed on CRD pumps 1B, 2A and 3A (WO 06-721298-000, 06-720062-000, 05-721461, 06-721175-000) and these activities did not reveal or result in any significant problems related to CRD pump seals.

As a result of the inspectors' finding, the licensee issued PER 116114 on December 7, 2006, addressing the failure to fully implement the corrective actions from PER 03-020163-000. The licensee made a revision (Rev. 15) to the procedure including a note regarding the need to disassemble the CRD pump speed increaser, and provide information notes addressing the clearance between the gland plate assembly and the drive collar of the mechanical seal assembly. The inspectors verified that the note regarding the spacer was consistent with Vendor Document BFN-VTD-C681-0010, Installation Instructions for John Crane 8B-1 Seals, and the need for removing the spacer prior to starting the pump. In accordance with Inspection Manual Chapter 0612, this issue is characterized as a minor finding in that there were no safety consequences as a result of the inadequately revised maintenance procedure, which is similar to Examples 4.d, 4.e, and 4.g of IMC 0612 Appendix E.

In addition, the inspectors noted that a Green NCV was issued by the NRC's PI&R inspection team in December 2005 (IR 05000259/2005011) for other issues involving PER corrective actions that were not adequately implemented contrary to 10 CFR 50 Appendix B, Criterion XVI. These previous examples of failing to fully implement PER corrective actions identified by the NRC were already being addressed by the licensee, and the licensee's generic corrective actions were generally considered acceptable. The additional example of inadequate corrective actions from PER 03-020163-000 was being evaluated by the licensee for any further extent of condition actions.

PER 55820

During the power ascension from the Unit 2 Cycle 12 refueling outage on March 26, 2003, the 2A recirculation pump tripped as a result of an invalid output ground fault indication in its Variable Frequency Drive (VFD). Several hours later the 2B recirculation pump also tripped due to a similar cause. Abnormal Operating Instructions, 2-AOI-68-1B, implemented the conditions of TS 3.1.1.1-I, and required Operations personnel to manually scram the reactor when both recirculation pumps tripped. As a result the licensee reported the event to the NRC in LER 50-260/2003-003-00.

This PER was categorized as a Level A, which required a root cause investigation. The licensee obtained a root cause analysis from the vendor which determined the failure to have been caused by a process deficiency and related hardware issues. Based on the vendor's recommendation, the licensee determined the root cause to be an inadequacy in Design Standards for specifying the generation reliability requirements and failure to adequately investigate the cause of ground fault trips which occurred earlier in the post-maintenance testing. A significant contributor to both of these failures was lack of sufficient information about the VFD control functions. In response to the trip, the vendor increased the setpoint value and the time constant. The inspectors reviewed the root cause analysis and the event investigation, and verified that changes to drawings and documents were made in accordance with the corrective actions specified. The inspectors also performed a walkdown of the Unit 1 VFD also identified as part of the extent of condition in PER 55820.

.4 Focused Annual Sample Review

The inspectors performed a review of the Unit 2 and 3 control room disabled annunciators. The inspectors reviewed the technical evaluations and 10 CFR 50.59 documentation associated with the disabled annunciators.

a. Inspection Scope

The inspectors reviewed the Unit 2 and 3 disabled annunciators, in particular those associated with the control rod drive high temperature indicators which constituted the majority of disabled annunciator inputs. The inspectors performed a general review of the other disabled annunciators to ensure proper documentation.

b. Findings and Observations

Control Rod Drive High Temperature Disabled Annunciators

Unit 2 has multiple inputs to the control rod drive high temperature annunciators disabled dating back to 1997. Each of the inputs has been properly evaluated in accordance with plant procedure OPDP-4, Annunciator Disablement. The inspectors reviewed the technical evaluation and 10 CFR 50.59 evaluations, and determined that they were accurate and complete. The inspector also reviewed the associated PER and work orders and noted that the work orders were written on March 21, 2004, and scheduled for the Unit 2 outage. The inspectors also examined the integrated computer system display of individual CRD temperatures on multiple occasions over a period of time to verify the intermittent nature of the failures.

General Review

The licensee's annunciator disablement procedure (OPDP-4) required that an annunciator that has been disabled for maintenance shall have a 10 CFR 50.59 review performed if the disablement exceeds 90 days. Annunciator 0-XA-55-10 Window 40, the number 1 cooling tower transformer gas pressure high/low, was disabled on February 21, 2006. As of December 9, 2006, there was one 10 CFR 50.59 evaluation attached to the technical evaluation. Two days after the inspector questioned the licensee about the discrepancy, the licensee informed the inspector that engineering had not performed a 10 CFR 50.59 because the issue had been resolved by engineering in March of 2006. Engineering had not communicated to Operations that the issue had been resolved, and as such the alarm had not been removed from the disabled list.

The inspector noted that procedure OPDP-4 required that the disabled annunciator documentation be reviewed monthly per OPDP-4 Section 3.5. The inspector then questioned the licensee about the performance and documentation of the monthly review. The licensee indicated that this review should have been performed per the work control process. A PER 116340 was written to document the inspector's concerns regarding inconsistent monthly reviews. In accordance with Inspection Manual Chapter 0612, this issue is characterized as a minor finding in that there were no safety consequences as a result of the not implementing this operating procedure, which is similar to Example 2.g of IMC 0612 Appendix E.

4OA3 Event Follow-up

.1 (Closed) Licensee Event Report (LER) 05000296/2006-002-00, Manual Reactor Scram Due to Loss of the Reactor Recirculation Pumps.

a. Inspection Scope

On August 19, 2006, Unit 3 was manually scrammed from 100% power due to the simultaneous loss of both the 3A and 3B Variable Frequency Drives (VFD) that was caused by a failure of the VFD control system. The initial followup of this event by the inspectors was documented in Section 4OA3.1 of IR 0500096/2006-04. Since then the inspectors have reviewed the applicable LER that was issued on October 17, 2006, and its associated PER 109107, which included the root cause determination and corrective action plans. The principal root cause of the Unit 3 reactor scram was attributed to a lockup of the VFD central processing units due to excessive traffic (i.e., interference or data storm) from the interconnected plant computer network. The lack of an internal firewall system/device between the plant network and the VFD controllers made these controllers susceptible to network disturbances.

b. Findings

No significant findings or violations of NRC requirements were identified. This LER is closed.

.2 (Closed) LER 05000296/2006-003-00, Manual Reactor Scram in Response to Main Turbine EHC System Fluid Leak.

a. Inspection Scope

On August 29, 2006, Unit 3 was manually scrammed from 100% power due a large, unisolable electro-hydraulic control (EHC) fluid leak caused by an O-ring failure at the connection between the fast acting solenoid valve (FASV) and the main turbine #2 Control Valve. The initial followup of this event by the inspectors was documented in Section 4OA3.2 of IR 05000296/2006-04. Since then, the inspectors have reviewed the applicable LER that was issued on October 16, 2006, and its associated PER 109756, which included the root cause determination and corrective action plans. The principal root cause was determined to be inadequate O-ring compression due to the mounting bolts supplied with the FASV being slightly too long.

b. Findings

No significant findings or violations of NRC requirements were identified. This LER is closed.

4OA5 Other

.1 Independent Spent Fuel Storage Installation (ISFSI) Radiological Controls.

a. Inspection Scope

The inspector conducted independent area radiation surveys of the ISFSI facility and compared the results to previous weekly surveys. The inspectors also toured the ISFSI facility and observed and evaluated implementation of radiological controls, including Radiological Work Permits and radiological postings, thermoluminescent dosimeter locations and conditions, access controls, radiological surveillances and discussed the controls with a Health Physics Technician and Health Physics supervisory staff. Radiological controls for loading Hi-Storm ISFSI casks were also reviewed and discussed.

Radiological control activities for ISFSI areas were evaluated against 10 CFR Parts 20 and 50, NRC Certificate of Compliance Number 1014 and applicable licensee procedures. Documents reviewed are listed in Section 4OA5 of the report Attachment.

b. Findings

No findings of significance were identified.

.2 (Closed) NRC Temporary Instruction (TI) 2515/169, Mitigating Systems Performance Index (MSPI) Verification

a. Inspection Scope

During this inspection period, the inspectors completed a review of the licensee's implementation of the Mitigating Systems Performance Index (MSPI) guidance for reporting unavailability and unreliability of monitored safety systems in accordance with Temporary Instruction 2515/169.

The inspectors examined surveillances that the licensee determined would not render the train unavailable for greater than 15 minutes, or during which the system could be promptly restored through operator action, and therefore, were not included in unavailability calculations. As part of this review, the recovery actions were verified to be uncomplicated and contained in written procedures.

On a sample basis, the inspectors reviewed operating logs, work history information, maintenance rule information, corrective action program documents, and surveillance procedures to determine the actual time periods the MSPI systems were not available due to planned and unplanned activities. The results were then compared to the baseline planned unavailability and actual planned and unplanned unavailability determined by the licensee to ensure the data's accuracy and completeness. Likewise, these documents were reviewed to ensure MSPI component unreliability data determined by the licensee identified and properly characterized all failures of monitored components. The unavailability and unreliability data were then compared with performance indicator data submitted to the NRC to ensure it accurately reflected the performance history of these systems.

b. Findings and Observations

No findings of significance were identified.

With a number of minor exceptions, the licensee accurately documented the baseline planned unavailability hours, the actual unavailability hours and the actual unreliability information for the MSPI systems. No significant errors in the reported data were identified, which resulted in a change to the indicated index color. No significant discrepancies were identified in the MSPI basis document which resulted in: (1) a change to the system boundary, (2) an addition of a monitored component, or (3) a change in the reported index color.

4OA6 Management Meetings

Exit Meeting Summary

On January 9, 2007, the resident inspectors presented the integrated inspection results to Mr. Bruce Aukland, and other members of his staff. On January 29, 2007, in a conference call, the Chief of Engineering Branch 2 presented the finding in Section 1R21 to Mr. Brian O'Grady and other members of his staff. The licensee acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection period.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

B. Aukland, Nuclear Plant Manager
T. Brumfield, Site Nuclear Assurance Manager
J. Burton, Design Engineering Manager
D. Campbell, Lead Requalification Training Instructor
P. Chadwell, Operations Superintendent
J. Corey, Radiation Protection Manager
W. Crouch, Nuclear Site Licensing & Industry Affairs Manager
R. Davenport, Work Control and Planning Manager
J. DeDimenico, Asst. Nuclear Plant 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
D. Langley, Site Licensing Supervisor
D. Matherly, Human Performance Manager
J. Mitchell, Site Security Manager
D. Nye, Maintenance & Modifications Manager
B. O'Grady, Site Vice President
C. Ottenfeld, Chemistry Manager
C. Rasby, Supervisor - Medical
D. Sanchez, Training Manager
E. Scillian, Operations Training Manager
J. Sparks, Outage Manager
J. Steele, Outage Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Open
None

Opened and Closed

05000260, 296/2006005-01	NCV	Lack of Assured Cooling Water for Emergency Diesel Generators During SBO Conditions (Section 1R21)

Closed

05000296/2006-002-00	LER	Manual Reactor Scram Due to Loss of the Reactor Recirculation Pumps (Section 4OA3.1)
05000296/2006-003-00	LER	Manual Reactor Scram in Response to Main Turbine EHC System Fluid Leak (Section 4OA3.2)

2515/169 (Units 2 and 3)	TI	Mitigating Systems Performance Index Verification (Section 4OA5.2)

Discussed
None

LIST OF DOCUMENTS REVIEWED

Section 1R06: Flood Protection Measures

2-OI-74; Residual Heat Removal System Procedure, Section 8.35; Revision 129, dated May 9, 2006
B22 88 0401 003; Withdrawal Of Volume III Commitment Requiring Moderate Energy Line Break (MELB) Flooding Evaluation; dated April 1, 1988
Design Basis Evaluation Report For Moderate Energy Line Break (MELB) Flood Evaluation requirements For BFN Unit 2 restart; dated March 31, 1988
0-ARP-25-17A; Alarm Response Procedure For Panel 25-17 XA-55-17A, Panel 18; revision 9, dated August 25, 2006
2-EOI-3-Flowchart; Secondary Containment Control; Revision 11
R92 950918 982; Submergence Qualification of RHRSW Cables and/or Circuits; dated September 18, 1995
SD-E12.5.3; Cable Splicing Medium Voltage (5 - 15KV) Insulated Conductors; Revision 6, dated September 13, 1977
PER 116575; Potential To Have Submerged Medium Voltage Cables; dated December 13, 2006

Section 1R17: Permanent Plant Modifications

DCN 64473, Replace U2 Unit Preferred MMG Set AC Drive Motor Feeder Breaker & Trip Device
WO, 06-722293-001, Troubleshooting Plan for BFN-2-BKR-252-0002A/7D
PIC 68504, Updated Breaker Settings
EPI-0-000-BKR009, Checkout and Test of GE Type AK-15/25 Circuit Breakers After Overhaul, Rev. 0009
EPI-0-000-BKR020, Testing and Troubleshooting of 250 VDC and 480 VAC Power Circuit Breakers and Trip Devices, Rev. 0034

Section 1R21: Safety System Design and Performance Capability

Calculation MD-Q0999-920053, “Station Blackout - Multi-Unit HVAC and DG Availability Analysis,” Rev. 8
Procedure AOI-57-1A, “Loss of Offsite Power (161 and 500 KV)/Station Blackout,” Rev. 64
UFSAR Section 8.10, “Station Blackout”

PER 114913, “LOOP/SBO procedure did not adequately address potential loss of all EECW”
PER 114967, “SBO calculation did not adequately consider potential loss of all EECW”

Section 4OA5.1: Independent Spent Fuel Storage Installation (ISFSI) Radiological Controls

Procedures and Guidance Documents
Tennessee Valley Authority (TVA), Browns Ferry Nuclear Plant (BFNP), Unit 0, Radiological Control Instruction (RCI), RCI-28, HI-TRAC Average Surface Dose Rates, Revision (Rev.) 0001, Dated 09/25/06
TVA, BFNP, Unit 0, RCI, RCI-29, HI-TRAC Contamination Surveys, Rev. 0001, Dated 09/25/06
TVA, BFNP, Unit 0, RCI, RCI-30, HI-STORM Average Surface Dose Rates, Rev. 0002, Dated 09/21/06
TVA, BFNP, Radiological Protection Procedure, ASIL-16-Radiological Protection Periodic Routines, Rev. 81, Dated 11/05/06

Records and Data
Browns Ferry Radiological Surveys, M0464.001 - M0464 ISFSI Pad, Survey Numbers 110106-1, 110806-2, 111506-7, 112206-01, 112906-17, and 120606-3, Dated 11/01/06, 11/08/06, 11/15/06, 11/22/06, 11/29/06, and 12/06/06, Respectively
TLD Environmental Trending for Dry Cask Storage Pad, 3rd Quarter 2005 to 3rd Quarter 2006

CAP Documents
Nuclear Assurance (N/A) - Audit Report No. BFA0507 - Browns Ferry (BFN), Independent Spent Fuel Storage Installation (ISFSI) Audit, Dated July 12, 2006
W76 051021 818, NA-BF-05-034, QA Record, BFN - NA - Oversight Report for the Period of July 1, 2005 Through September 30, 2005 - NA-BF-05-034, Dated October 21, 2005

Section 4OA5.2: Mitigating Systems Performance Index (MSPI) Verification

Procedures, Manuals, and Guidance Documents
Mitigating System Performance Index (MSPI) Basis Document, Revision 0
NEI 99-02 Rev 4 Regulatory Assessment Performance Indicator Guideline

Records and Data
Selected Control Room Logs, January 2004 through September 2006
System Health Reports for applicable systems
Maintenance Rule Spreadsheets for applicable systems
Work Order Histories for applicable systems
PI summary submittals for applicable systems
MSPI Derivation Report Unreliability Index for applicable systems
MSPI Derivation Report Unavailability Index for applicable systems

Corrective Action Program Documents
PER 112206, Errors in MSPI Basis Documents