**UNITED STATES**
**NUCLEAR REGULATORY COMMISSION**
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

August 8, 2011

Mr. R. M. Krich
Vice President, Nuclear Licensing
Tennessee Valley Authority
3R Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2011003, 05000260/2011003, AND 05000296/2011003

Dear Mr. Krich:

On June 30, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Browns Ferry Nuclear Plant, Units 1, 2, and 3. The enclosed inspection report documents the inspection results which were discussed on July 8, 2011, with Mr. Keith Polson and other members of your staff.

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

This report documents two self-revealing findings of very low safety significance (Green). Both of these findings were determined to involve violations of NRC requirements. Additionally, one licensee-identified violation which was determined to be of very low safety significance is listed in this report. However, because of the very low safety significance and they were entered into your corrective action program, the NRC is treating these issues as non-cited violations (NCVs) consistent with the Enforcement Policy. If you contest any NCV, 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: (1) the Regional Administrator, Region II; (2) the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and (3) the Senior Resident Inspector at Browns Ferry Nuclear Plant.

In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region II, and the Senior Resident Inspector at Browns Ferry Nuclear Plant. The information you provide will be considered in accordance with Inspection Manual Chapter 0305.

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 the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

Sincerely,

***/RA/***

Eugene F. Guthrie, 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: NRC Integrated Inspection Report 05000259/2011003, 05000260/2011003, and 05000296/2011003

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 the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

Sincerely,

*/RA/*

Eugene F. Guthrie, 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: NRC Integrated Inspection Report 05000259/2011003, 05000260/2011003, and 05000296/2011003

cc w/encl. (See page 3)

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

ADAMS: ☐ Yes ACCESSION NUMBER:__ML112210368_____ X SUNSI REVIEW COMPLETE

| OFFICE | RII:DRP | RII:DRP | RII:DRP | RII:DRP | RII:DRP | RII:DRP | |
|---|---|---|---|---|---|---|---|
| SIGNATURE | Via email | Via email | Via email | Via email | CRK /RA/ | EFG /RA/ | |
| NAME | TRoss | CStancil | PNiebaum | LPressley | CKontz | EGuthrie | |
| DATE | 08/05/2011 | 07/28/2011 | 07/28/2011 | 07/28/2011 | 08/05/2011 | 08/06/2011 | |
| E-MAIL COPY? | YES NO | YES NO | YES NO | YES NO | YES NO | YES NO | YES NO |

OFFICIAL RECORD COPY DOCUMENT NAME: G:\DRPII\RPB6\BROWNS FERRY\REPORTS\2011\BF 003\BROWNS FERRY 2011003.DOCX

cc w/encl:
K. J. Polson
Vice President
Browns Ferry Nuclear Plant
Tennessee Valley Authority
P.O. Box 2000
Decatur, AL 35609

C. J. Gannon
General Manager
Browns Ferry Nuclear Plant
Tennessee Valley Authority
P.O. Box 2000
Decatur, AL 35609

J. E. Emens
Manager, Licensing and Industry Affairs
Browns Ferry Nuclear Plant
Tennessee Valley Authority
P.O. Box 2000
Decatur, AL 35609

E. J. Vigluicci
Assistant General Counsel
Tennessee Valley Authority
6A West Tower
400 West Summit Hill Drive
Knoxville, TN 37902

State Health Officer
Alabama Dept. of Public Health
RSA Tower - Administration
Suite 1552
P.O. Box 30317
Montgomery, AL 36130-3017

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

James L. McNees, CHP
Director
Office of Radiation Control
Alabama Dept. of Public Health
P. O. Box 303017
Montgomery, AL 36130-3017

Letter to R. M. Krich from Eugene F. Guthrie date August 8, 2011

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2011003, 05000260/2011003, and 05000296/2011003

Distribution w/encl:
C. Evans, RII
L. Douglas, RII
OE Mail
RIDSNRRDIRS
PUBLIC
RidsNrrPMBrownsFerry Resource

**U.S. NUCLEAR REGULATORY COMMISSION**

**REGION II**

| | |
|---|---|
| Docket Nos.: | 50-259, 50-260, 50-296 |
| License Nos.: | DPR-33, DPR-52, DPR-68 |
| Report No.: | 05000259/2011003, 05000260/2011003, 05000296/2011003 |
| Licensee: | Tennessee Valley Authority (TVA) |
| Facility: | Browns Ferry Nuclear Plant, Units 1, 2, and 3 |
| Location: | Corner of Shaw and Nuclear Plant Roads<br>Athens, AL  35611 |
| Dates: | April 1, 2011, through June 30, 2011 |
| Inspectors: | T. Ross, Senior Resident Inspector<br>C. Stancil, Resident Inspector<br>P. Niebaum, Resident Inspector<br>L. Pressley, Resident Inspector |
| Approved by: | Eugene F. Guthrie, Chief<br>Reactor Projects Branch 6<br>Division of Reactor Projects |

Enclosure

## SUMMARY OF FINDINGS

IR 05000259/2011003, 05000260/2011003, 05000296/2011003; 04/01/2011 – 06/30/2011; Browns Ferry Nuclear Plant, Units 1, 2 and 3; Annual Heat Sink Performance, Operability Evaluations.

The report covered a three month period of inspection by the resident inspectors. Two non-cited violations (NCV) were identified. The significance of most findings is identified by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP); the cross-cutting aspect was determined using IMC 0310, "Components Within the Cross-Cutting Areas". Findings for which the SDP does not apply may be Green or be 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 4, dated December 2006.

A. <u>NRC Identified and Self-Revealing Findings</u>

Cornerstone: Mitigating Systems

- <u>Green</u>. A self-revealing non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, was identified for the licensee's failure to take prompt corrective actions to preclude repetition of a significant condition adverse to quality (SCAQ) that resulted in the loss of a emergency diesel generator (EDG) safety function due to excessive heat exchanger fouling. On August 4, 2010 the licensee identified a SCAQ due to excessive fouling of the Unit 1/2 D EDG heat exchangers which resulted in a functional failure of the D EDG. Prompt corrective actions were not taken to preclude repetition because on June 5, 2011, excessive fouling was identified on the 3D EDG heat exchangers which resulted in a functional failure of the 3D EDG. Corrective actions taken by the licensee included cleaning and returning the 3D EDG heat exchangers to an operable status, and increasing monitoring of emergency equipment cooling water (EECW) cooling flow to all the EDG heat exchangers from weekly to every two days. The licensee entered this issue into their corrective action program as problem evaluation report (PER) 381569.

  This finding was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the excessive fouling of the 3D EDG heat exchanger was a functional failure and resulted in unplanned unavailability of the 3D EDG. In accordance with Inspection Manual Chapter (IMC) 0609 Attachment 4, Phase I - Initial Screening and Characterization of Findings, this finding was determined to be of very low safety significance because it did not represent an actual loss of safety function of a single train for more than its technical specification allowed outage time of seven days, or screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. The cause of this finding was directly related to the cross-cutting aspect of Maintaining Long Term Plant Safety (Equipment Issues) in the Resources component of the Human

Performance area because of the licensee's failure to minimize the duration of a long-standing degraded equipment issue related to relic clam shells in the EECW system which resulted in a repetitive functional failure of an EDG due to excessive heat exchanger fouling. [H.2.(a)]. (Section 1R07)

- Green. A self-revealing non-cited violation of 10 CFR 50 Appendix B, Criteria XVI, Corrective Action, was identified for the licensee's failure to promptly correct a condition adverse to quality related to Unit 1 High Pressure Coolant Injection (HPCI) system testable check valve which resulted in over-pressurization and significant damage to the HPCI system. Specifically, binding of the actuator linkage connected to the valve disc shaft caused the valve disc to physically stick open following a HPCI injection event. Subsequent opening of the inboard HPCI injection valve in preparation for a routine HPCI venting evolution resulted in over-pressurization of the HPCI system. The licensee repaired the damage to the HPCI system and temporarily modified the valve actuator linkage to remove any potential for binding until more permanent repairs could be performed in a unit outage. The licensee entered this issue into their corrective action program as problem evaluation report (PER) 372659.

  This finding was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, the stuck open testable check valve resulted in over-pressurization of the HPCI system, significant damage to HPCI components, and loss of the HPCI function. In accordance with Inspection Manual Chapter (IMC) 0609 Attachment 4, Phase I - Initial Screening and Characterization of Findings, this finding was determined to be of very low safety significance because it did not represent a loss of system safety function or screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. The Automatic Depressurization System (ADS) was available at all times to support the coolant injection safety function. The cause of this finding was directly related to the cross-cutting aspect of Thorough Evaluation of Identified Problems in the Corrective Action Program component of the Problem Identification and Resolution area, because of the licensee's inadequate evaluation of PER 289169 for the abnormal check valve actuator open indication that subsequently resulted in an over-pressurization and loss of function of the Unit 1 HPCI system [P.1.(c)]. (Section 1R15)

B. Licensee Identified Violations

One violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. The violation and the corrective action program tracking number is listed in Section 4OA7 of this report.

## REPORT DETAILS

Summary of Plant Status

Unit 1 operated at essentially full Rated Thermal Power (RTP) for most of the report period except for one unplanned downpower and an automatic reactor scram. On April 27, 2011, an unplanned downpower to 75 percent RTP was conducted due to grid instability caused by severe weather. Later that same day, unit 1 automatically scrammed when the 500 KV electrical grid outside of the Browns Ferry owner controlled area was lost as a result of tornado damage. Following extensive grid repairs throughout the state, Unit 1 restarted on May 19, 2011. However, the unit remained at approximately 20 percent RTP for seven days to inspect and repair the high pressure coolant injection (HPCI) system that was damaged by an inadvertent over-pressurization event, and to repair an unisolable main steam leak from a main turbine first stage pressure instrument penetration. Following completion of HPCI and main turbine repairs, unit 1 returned to full RTP on May 28, 2011.

Unit 2 began the report period in a shutdown condition for refueling outage (RFO) U2R16. The unit was restarted on April 5, 2011, and returned to full RTP on April 13. Unit 2 operated at essentially full RTP for most of the remaining report period except for two unplanned downpowers, and an automatic reactor scram. On April 27, 2011, an unplanned downpower to 75 percent RTP was conducted due to grid instability caused by severe weather. Later that same day, unit 2 automatically scrammed when the 500 KV electrical grid outside of the Browns Ferry owner controlled area was lost as a result of extensive tornado damage. Following extensive grid repairs throughout the state, the unit restarted on May 23, and returned to full RTP on May 28, 2011. On June 7, 2011, an unplanned load reduction to 23 percent RTP was conducted as a result of automatic voltage regulator (AVR) alarms. The main turbine generator was removed from service on June 8 to implement a temporary modification to the AVR system. Unit 2 was then returned to full RTP on June 10, 2011.

Unit 3 operated at essentially full RTP for most of the report period except for one planned downpower and an automatic reactor scram. On April 12, a planned downpower to 95 percent RTP was conducted to repair a steam leak on the 3A1 reactor feedwater heater. The unit returned to full RTP the same day. On April 27, 2011, the unit automatically scrammed when the 500 KV electrical grid outside of the Browns Ferry owner controlled area was lost as a result of tornado damage. Following extensive grid repairs throughout the state, Unit 3 restarted on May 31, and returned to full RTP on June 4, 2011.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

.1 Offsite and Alternate AC Power Systems Readiness

a. Inspection Scope

Prior to the 2011 summer season, but during seasonal high temperatures, the inspectors reviewed electrical power design features, onsite risk and work management procedures, and corporate transmission and power supply procedures to verify appropriate operational oversight and assurance of continued availability of offsite AC power systems. Inspectors verified that communications protocols existed between the transmission system operator and Browns Ferry Nuclear Plant for coordination of off-normal and emergency events affecting the plant, event details, estimates of return-to-service times, and notifications of grid status changes. Inspectors also verified that procedures included controls to adequately monitor both offsite AC power systems (including post-trip voltages) and onsite alternate AC power systems for availability and reliability. Furthermore, inspectors interviewed onsite licensed operators to determine their understanding and implementation of the power monitoring and assessment process. Inspectors reviewed the material condition of offsite AC power systems and onsite alternate AC power systems to the plant, including switchyard and transformers. This review included review of outstanding work orders affecting these systems and a walkdown of the switchyard with operations personnel to ensure the systems will continue to provide appropriate "as designed" capabilities.

b. Findings

No findings were identified.

.2 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

Prior to and during the onset of hot weather summer conditions, the inspectors examined the licensee's implementation of 0-GOI-200-3, Hot Weather Operations, including Attachment 1, Hot Weather Operational Checklist. The inspectors also reviewed the Hot Weather Discrepancy List of work orders designated with a hot weather (HW) priority code. The inspectors discussed implementation of 0-GOI-200-3 with responsible Work Control and Operations personnel and management. Furthermore, the inspectors conducted walkdowns of the following important HW-related equipment that could potentially affect operability risk significant systems during extreme hot weather conditions: Raw Cooling Water (RCW) pumps; Reactor Building and Refuel Floor Supply Fans and Ventilation; Unit 3 Control Bay and Main Control Room Chillers and Ventilation; and Unit 1/2 Control Bay and Main Control Room Chillers and Ventilation.

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

The inspectors conducted three partial equipment alignment walkdowns to evaluate the operability of selected redundant trains or backup systems, listed below, while the other train or subsystem was inoperable or out of service. The inspectors reviewed the functional systems descriptions, Updated Final Safety Analysis Report (UFSAR), system operating procedures, and Technical Specifications (TS) to determine correct system lineups for the current plant conditions. The inspectors performed walkdowns of the systems to verify that critical components were properly aligned and to identify any discrepancies which could affect operability of the redundant train or backup system.

- Unit 1 Residual Heat Removal (RHR) System, Division II
- Unit 3 B Emergency Diesel Generator (EDG) Restoration Following Six-Year Preventive Maintenance
- Units 1 and 3 Main Banks 1 and 3 Batteries Following Unloading of Main Bank 2 Battery for a Modified Performance Test

b. Findings

No findings were identified.

1R05 Fire Protection

.1 Fire Protection Tours

a. Inspection Scope

The inspectors reviewed licensee procedures, Nuclear Power Group Standard Programs and Processes (NPG-SPP)-18.4.7, Control of Transient Combustibles, and NPG-SPP-18.4.6, Control of Fire Protection Impairments, and conducted a walkdown of five fire areas (FA) and fire zones (FZ) listed below. Selected FAs/FZs 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 NPG-SPP-18.4.6. 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 firefighting equipment, such as fire extinguishers, hose stations, ladders, and communications equipment, was in place. This activity constituted five inspection samples.

- Unit 1 Reactor Building, EL 593’ North of Column Line R (FZ 1- 3)
- Unit 1 Reactor Building, EL 593’ South of Column Line Q, and RHR Heat Exchanger Rooms, EL 565’ and 593’ (FZ 1-4)
- Unit 1 Reactor Building, EL 621 and 639 North of Column Line R (FZ 1-5)
- Unit 1 Reactor Building, EL 639 South of Column Line R (FZ 1-6)
- Unit 2 Reactor Building, EL 519’ through EL 565’ (FZ 2-2)

b. Findings

No findings were identified.

1R07 Annual Heat Sink Performance

a. Inspection Scope

The inspectors examined activities associated with the Unit 1, 2 and 3 EDG heat exchangers supplied by emergency equipment cooling water (EECW). The inspectors performed walkdowns of key components for the eight Unit 1, 2, and 3 diesel generator cooling systems to verify material conditions were acceptable and physical arrangement matched procedures and drawings. The inspectors also witnessed the 3A EDG EECW heat exchanger inspection. In addition, the inspectors reviewed heat exchanger inspection results, and flow-rate testing procedures and results to evaluate the licensee’s program for maintaining heat sinks in accordance with the licensing basis and industry standards. Furthermore, the inspectors reviewed diesel generator heat exchanger critical operating parameters, periodic and corrective maintenance records, and periodic heat exchanger inspections to verify that the licensee’s maintenance methodology was in accordance with EPRI Report NP 7552, "Heat Exchanger Performance Monitoring Guidelines"; NPG-SPP-09.14, “Generic Letter (GL) 89-13 Implementation”; and 0-TI-522, “Program for Implementing NRC Generic Letter 89-13”. Lastly, the inspectors reviewed applicable PERs and associated corrective actions to verify that the licensee was identifying GL 89-13 issues and addressing them within the corrective action program (CAP).

b. Findings

Introduction: A Green self-revealing non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, was identified for the failure to take prompt corrective actions to preclude repetition of a significant condition adverse to quality (SCAQ) that resulted in the functional failure of the 3D EDG due to excessive heat exchanger fouling.

Description: Since July 2009, low EECW flow in the EDG heat exchangers has been a recurring problem due to excessive fouling. To manage this persistent problem the licensee established interim corrective actions to monitor and trend EECW flow using temporary instrumentation in February 2010 and September 2010, for the Unit 3 and Unit 1/2 EDGs, respectively. This issue was also determined to be a degraded condition pursuant to Regulatory Issue Summary 2005-20, Operability Determinations and Functionality Assessments for Resolution of Degraded or NonConforming Conditions

Adverse to Quality or Safety. As part of PER 254463, the licensee issued a functional evaluation in October 2010 to evaluate operability of the degraded EECW system conditions due to recurring relic clamshell fouling of EECW coolers and EDG heat exchangers that result in reduced EECW flow below required limits. The licensee's determination of continued operability with this degraded condition was based upon routine monitoring and trending, with heat exchanger cleaning as necessary, until longterm corrective actions to flush the EECW headers could be accomplished.

On August 4, 2010, a SCAQ was identified by the licensee for excessive fouling of the Unit 1/2 'D' EDG EECW heat exchangers that was discovered on June 28, 2010. The licensee determined that the low EECW flow condition of the D EDG heat exchangers resulted in a functional failure of the D EDG based on actual flowrate and river water inlet temperature. To address this issue, problem event report (PER) 243132 was initiated as an 'A' level PER requiring a root cause evaluation. In accordance with licensee procedure NPG-SPP-03.1, Corrective Action Program, an SCAQ was defined as "A condition adverse to quality that in the judgment of management will require root cause determination to assure reasonable corrective actions to preclude recurrence. [10CFR50 Appendix B Criterion XVI] These issues are documented in Level A PERs." The licensee concluded that the root cause of the D EDG heat exchanger fouling was a programmatic issue because an effective EECW flushing program had not been established to work together with the chemical treatment and raw water programs for eliminating or reducing clamshells in low flow or stagnant piping locations. A corrective action to prevent recurrence (CAPR) for this root cause was to purge relic clamshells from the EECW system by flushing the EECW system main header and treating/flushing all EECW stagnant lines. The approved due date for this CAPR was March 15, 2011, according to the root cause report. However, based on discussions with licensee management, and review of the PER 243132 corrective action plan, to verify status of the CAPR to flush the EECW main header, the inspectors determined the associated due date was extended to June 30, 2011, and then again to August 31, 2011.

On June 5, 2011, the Unit 3D EDG heat exchangers' EECW flow was measured and determined to be below the minimum allowed flowrate which was indicative of excessive fouling. The measured EECW flow to the 3D EDG heat exchangers was 282 gallons per minute (gpm) with an operability requirement of at least 450 gpm for an inlet temperature of 95F. On June 5, 2011 the EECW inlet temperature to the EDG heat exchangers was approximately 85F. For an inlet temperature of 85F, the minimum required EECW flow for EDG operability was 364 gpm. The licensee declared the 3D EDG inoperable upon discovery of reduced EECW flow, cleaned the associated heat exchangers, and initiated PER 381569 on June 6, 2011. The inspectors reviewed the licensee's past operability report that stated the recent fouling condition of the 3D EDG heat exchangers observed in June 2011 was attributed to relic clam shells, river grass, debris, etc. The inspectors also reviewed the licensee's apparent cause evaluation (ACE) for the 3D EDG. This ACE stated that a ¼ inch gap in the EECW strainer due to misalignment of the strainer basket was the most probable cause of the majority of the 3D EDG heat exchanger fouling from river grass. However, the licensee's ACE also recognized that a significant contributing cause to the excessive fouling of the 3D EDG heat exchangers was the relic clam shells that were most likely stirred up during recent EECW system header perturbations (e.g., EECW header realignment and pump starts). The 3D EDG heat exchangers were returned to service on June 6, 2011. On July 1, 2011, the licensee determined that the 3D EDG would not have fulfilled it safety function due to the excessive heat exchanger fouling. Corrective actions taken by the licensee included cleaning the 3D EDG heat exchangers. Additionally, the licensee initiated more frequent monitoring of EECW cooling flow to all the EDG heat exchangers from weekly to every 2 days.

Analysis: The inspectors determined that the licensee's failure to take prompt corrective actions to preclude repetition of a significant condition adverse to quality (SCAQ) that resulted in the loss of an EDG safety function due to excessive DG heat exchanger fouling was a performance deficiency. The finding is more than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the excessive fouling of the 3D diesel generator heat exchangers resulted in a functional failure and unplanned unavailability of the 3D EDG. The significance of the finding was evaluated using Phase 1 of the SDP in accordance with the IMC 0609 Attachment 4, and was determined to be of very low safety significance (Green) because the finding did not represent an actual loss of safety function of a single train for more than its technical specification allowed outage time of seven days or screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. The cause of this finding was directly related to the cross-cutting aspect of Long Term Safety (Equipment Issues) in the Resources component of the Human Performance area because of the licensee's failure to minimize the duration of a long-standing degraded equipment issue related to relic clam shells in the EECW system which resulted in a repetitive functional failure of an EDG due to excessive EDG heat exchanger fouling. [H.2.(a)].

Enforcement: 10CFR50 Appendix B, Criterion XVI, Corrective Action, required in part that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Additionally, in the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. Contrary to the above, the licensee failed to take prompt corrective actions to preclude a repeat functional failure of an EDG due to excessive heat exchanger fouling. This issue was designated an SCAQ in accordance with licensee procedure NPG-SPP-03.1, Corrective Action Program, as "A condition adverse to quality that in the judgment of management will require root cause determination to assure reasonable corrective actions to preclude recurrence." Specifically, on August 4, 2010, a SCAQ had been identified due to excessive fouling of the Unit 1/2 'D' diesel generator heat exchangers, which had resulted in a functional failure of this EDG. Corrective actions to preclude repetition were not effective because on June 5, 2011, excessive fouling of the 3D diesel generator heat exchangers was identified which resulted in a functional failure of the 3D EDG. Because this finding was determined to be of very low safety significance (GREEN) and has been entered into the licensee's CAP as PER 381569, this violation is being treated as an NCV consistent with the Enforcement Policy. This NCV is identified as NCV 05000259, 260, and 296/2011003-01, Failure to Take Corrective Actions to Preclude a Repetitive Functional Failure of an EDG due to Excessive Heat Exchanger Fouling.

1R11 Licensed Operator Requalification

a. Inspection Scope

On June 13, 2011, the inspectors observed an as-found licensed operator requalification simulator examination for an operating crew according to Unit 2 Simulator Evaluation Guide OPL177.041, Hydrogen (H2) Supply Alarm, HPCI Pressure Switch Failure, Condenser Tube Leak, Fuel Failure, Main Steam Line Leak, Un-isolable RCIC Steam Line Break, HPCI Failure, 2 Area Rad Levels Above Max Safe.

The inspectors specifically evaluated the following attributes related to the operating crew's 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 (AOIs), and Emergency Operating Instructions (EOIs)
- 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 attended the post-examination critique to assess the effectiveness of the licensee evaluators, and to verify that licensee-identified issues were comparable to issues identified by the inspector. The inspectors also reviewed simulator physical fidelity (i.e., the degree of similarity between the simulator and the reference plant control room, such as physical location of panels, equipment, instruments, controls, labels, and related form and function). This activity counts for one inspection sample.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness

.1 Routine

a. Inspection Scope

The inspectors examined two specific equipment issues listed below for structures, systems and components (SSC) within the scope of the Maintenance Rule (MR) (10CFR50.65) with regard to some or all of the following attributes, as applicable: (1) Appropriate work practices; (2) Identifying and addressing common cause failures; (3) Scoping in accordance with 10 CFR 50.65(b) of the MR; (4) Characterizing reliability issues for performance monitoring; (5) Charging unavailability for performance monitoring; (6) Balancing reliability and unavailability; (7) Trending key parameters for condition monitoring; (8) System classification and reclassification in accordance with 10 CFR 50.65(a)(1) or (a)(2); (9) Appropriateness of performance criteria in accordance with 10 CFR 50.65(a)(2); and (10) Appropriateness and adequacy of 10 CFR 50.65 (a)(1) goals and corrective actions (i.e. – Ten Point Plan). The inspectors also compared the licensee's performance against site procedure NPG-SPP-3.4, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting; Technical Instruction 0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting; and NPG-SPP 3.1, Corrective Action Program. The inspectors also reviewed, as 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.

- Unit 3 Cycle U3C15 Fuel Failure
- 4160 kV Electrical System, Development of Unavailability Performance Criteria

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

For planned online work and/or emergent work that affected the combinations of risk significant systems listed below, the inspectors reviewed five maintenance risk assessments, and actions taken to plan and/or control work activities to effectively manage and minimize risk. The inspectors verified that risk assessments and applicable risk management actions (RMA) were conducted as required by 10 CFR 50.65(a)(4) and applicable plant procedures such as NPG-SPP-7.0, Work Management; NPG-SPP-7.1, On-Line Work Management; 0-TI-367, BFN Equipment to Plant Risk Matrix; NPG-SPP-7.3, Work Activity Risk Management Process; and NPG-SPP-7.2, Outage Management. Furthermore, as applicable, the inspectors verified the adequacy of the licensee's risk assessments, implementation of RMAs, and plant configuration.

- Unit 1 HPCI, C 4KV Shutdown Board Battery, and Unit 2 Unit Preferred Motor Generator Set out of service (OOS)
- Units 1, 2, and 3 Loss of All Offsite 500 KV Lines, and A and 3B Diesel Generators OOS
- 1/2C, 3C and 3D EDG's OOS, A and G Control Air Compressors, 2D RHR, and 3B CRD OOS.
- 250V Battery Charger 4, A3 and C3 RHRSW/EECW pumps, G Control Air Compressor OOS
- 250V Battery Charger 4, A3 EECW pump, G control air compressor, B Control Bay Chiller, 3C EDG, 3B EDG, and 3A Control Bay Chiller OOS

b. Findings

No findings were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the five 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 NEDP-22, Functional Evaluations, to ensure that the licensee's evaluation met procedure requirements. Furthermore, where applicable, inspectors examined the implementation of compensatory measures to verify that they achieved the intended purpose 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.

- Unit 1: Collar on HPCI Booster Pump Missing Set Screws (PER 365041)
- Unit 1: HPCI Gland Seal Condenser Leaking (PER 372659)
- Units 2 and 3: AREVA Fuel SBLOCA Analysis Potential Degraded/Non-Conforming Conditions (PER 372764)
- Unit 1: Stuck Open High Pressure Coolant Injection (HPCI) System Testable Check Valve Resulting in Over-Pressurization of the HPCI System (PER 372659)
- Units 2 and 3: Primary Containment Isolation System (PCIS) CR120A Relay Replacements Due to Aging (PERs 348160, 379480, and 379469)

b. Findings

One finding was identified.

Introduction: A self-revealing Green non-cited violation of 10 CFR 50 Appendix B, Criteria XVI, Corrective Action, was identified for the licensee's failure to promptly correct a condition adverse to quality related to Unit 1 HPCI system testable check valve which resulted in over-pressurization and significant damage to the HPCI system.

Description: On May 20, 2011, while performing 1-SR-3.5.1.1(HPCI), Maintenance of Filled HPCI Discharge Piping, operators opened 1-FCV-073-0044, HPCI System Inboard Discharge Valve, to fill and vent portions of the HPCI system. During this evolution the HPCI discharge piping, suddenly and unexpectedly, pressurized to 1020 psig due to leakage past the 1-FCV-073-0045, HPCI System Testable Check Valve. A flood level alarm for the HPCI room was received in the Unit 1 main control room, and water was observed to be leaking from the HPCI gland seal condenser. Operations promptly shut 1-FCV-073-0044 to seal off the high pressure from the discharge piping and declared HPCI inoperable. Additionally, 1-FCV-073-0045, HPCI Testable Check Valve, was declared inoperable by Operations due to excessive seat leakage. The associated Primary Containment penetration flow path was isolated by closing and deactivating 1-FCV-073-0044 in the closed position. Subsequent inspection by the licensee identified extensive damage on the suction side of the Unit 1 HPCI system. The HPCI system was then tagged out for an approximately 10 day maintenance window (of a 14 day TS allowed outage time) to perform the necessary repairs and return the system to an operable status.

The Unit 1 HPCI injection testable check valve (i.e. 1-FCV-073-0045) was an air operated valve (AOV) with two sets of remote position indication (RPI) that indicated in the main control room. One set of open/close RPI was for the testable check valve disc position indication, while the other set of RPI was for the AOV actuator position. Subsequent investigation by the licensee confirmed that, prior to the Unit 1 HPCI overpressurization event on May 20, the FCV-73-45 actuator had indicated in the open position since November 24, 2010 (i.e., restart of Unit 1 from its last refueling outage). This abnormal open indication had been previously dispositioned by the licensee as an actuator indication problem only, as documented in PER 289169. The licensee’s basis for continued operability of FCV-73-45 was the satisfactory performance of surveillance tests 1-SR-3.6.1.3.5(SD), Valves Cycled During Cold Shutdown, and 1-SR-3.5.1.1(HPCI), Maintenance of Filled HPCI Discharge Piping, which was intended to verify the check valve and AOV actuator were in the closed position on November 22, 2010. However, after completion of a HPCI system flow rate test on November 24, the actuator RPI indicated in the open position while the valve disc RPI indicated in the closed position. Both the actuator and valve disc RPI should have indicated in the closed position. The inspectors found that verification of the check valve actuator position was part of the acceptance criteria for 1-SR-3.6.1.3.5(SD) which the inspectors concluded that the licensee failed to adequately evaluate in PER 289169 to ensure operability. With the check valve disc indicating in the closed position, the actuator should have also indicated in the closed position. The inspectors determined that this discrepancy following the HPCI flowrate test on November 24, 2010 was not adequately resolved before the May 20, 2011 over-pressurization event. After further investigation, the licensee determined that the actuator-to-disc shaft linkage was misaligned which caused binding that prevented the check valve from fully reseating (i.e., partially stuck open). The actuator “open” indication was indicative of the misaligned linkage.

In addition, the licensee determined that, just prior to the HPCI system over-pressurization event, Unit 1 experienced a reactor scram from a loss of offsite power on April 27, 2011. Following the reactor scram, the HPCI system was actuated twice to maintain reactor vessel water level (RVWL). During the initial actuation, the 1-FCV-073-0045 check valve disc indicated open in the control room approximately 10 seconds after HPCI flow had been established. During the second actuation, the check valve disc never indicated open even with flow through the system, which the licensee attributed to lower injection rates due to reduced decay heat. The licensee noted that the valve disc limit switch was set to indicate full open at the sixty degree disc open position. Inspectors concluded that the limit switch for check valve disc position was not set properly to provide accurate indication of valve position. During the HPCI system flow injection events on April 27 and 28, 2011, and the HPCI system over-pressurization on May 20, 2011, the HPCI testable check valve (1-FCV-073-0045) disc indicated closed when the valve disc was in fact physically open.

The licensee initiated PER 372659 to determine the cause of the HPCI system over-pressurization due to an apparently stuck open FCV-73-45 valve disc. The licensee's cause evaluation of the stuck open FCV-73-45 valve disc (PER 372659) determined that the failure of the valve to close was due to misalignment of the linkage between the actuator and valve stem. The licensee also initiated PER 397698 to determine the proper set point for the FCV-73-45 check valve disc RPI limit switch. The licensee implemented corrective actions to restore the HPCI system and FCV-73-45 to an operable status. The testable check valve was verified to operate smoothly and a leak tightness test of the free-swinging, self-aligning check valve disc was performed. Additionally, the licensee implemented temporary modification TACF 1-11-002-073 to remove the check valve actuator lever arm from the valve disc seat to further eliminate any possibility that the actuator would bind or prevent check valve motion. Furthermore, the licensee conducted walkdowns and evaluations for the Units 2 and 3 HPCI testable check valves to verify similar problems did not exist on Units 2 and 3.

Analysis: The inspectors determined that the licensee's failure to adequately evaluate and resolve an abnormal indication of the 1-FCV-73-45 actuator position was a performance deficiency. Failure to properly resolve the discrepancy between a simultaneous "open" actuator position indication and a "closed" valve disc position indication of 1-FCV-73-45, allowed the check valve to become stuck open and go undetected until the inadvertent over-pressurization of the Unit 1 HPCI system. According to IMC 0612, Appendix B, this finding was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of the HPCI system to respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the stuck open testable check valve resulted in over-pressurization of the HPCI system, significant damage to HPCI components, and loss of the HPCI function. In accordance with Inspection Manual Chapter (IMC) 0609 Attachment 4, Phase I - Initial Screening and Characterization of Findings, this finding was determined to be of very low safety significance because it did not represent a loss of system safety function or screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. The Automatic Depressurization System (ADS) in combination with the Low Pressure Coolant Injection (LPCI) and Core Spray (CS) Systems were available to provide the coolant injection safety function. The cause of this finding was directly related to the cross-cutting aspect of Thorough Evaluation of Identified Problems in the Corrective Action Program component of the Problem Identification and Resolution area, because the licensee's inadequate evaluation of PER 289169 for the check valve actuator open indication resulted in an over-pressurization and loss of function of the Unit 1 HPCI system [P.1.(c)]. (Section 1R15)

Enforcement: 10 CFR 50, Appendix B, Criteria XVI, states, in part, that measures shall be established to assure that conditions adverse to quality, such as malfunctioning equipment, are promptly corrected. Contrary to the above, the licensee failed to adequately evaluate and promptly correct the testable check valve actuator open indication which, along with inaccurate position indication of the check valve disc, resulted in over-pressurization and damage to the HPCI system. However, because the finding was determined to be of very low safety significance (Green) and has been entered into the licensee's CAP as PERs 372659 and 397698, this violation is being treated as an NCV consistent with the Enforcement Policy. This NCV is identified as NCV 05000259/2011003-02, Over-Pressurization of High Pressure Coolant Injection System due to Stuck Open HPCI System Testable Check Valve.

1R18 Plant Modifications

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the two temporary modifications listed below to verify regulatory requirements were met, along with procedures such as 0-TI-405, Plant Modifications and Design Change Control; 0-TI-410, Design Change Control; and NPG SPP-9.5, Temporary Alterations. The inspectors also reviewed the associated 10 CFR 50.59 screening and evaluation and compared each against the UFSAR and TS to verify that the modification did not affect operability or availability of the affected system. Furthermore, the inspectors walked down each modification to ensure that it was installed in accordance with the modification documents and reviewed post-installation and removal testing to verify that the actual impact on permanent systems was adequately verified by the tests.

- Temporary Alteration Control Form (TACF) 1-11-002-073, U1 HPCI System Testable Check Valve
- Jumper and Relay boots for Common Accident Signal Logic test 0-SR-3.8.1.6

b. Findings

No findings were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the seven post-maintenance tests (PMT) listed below to verify that procedures and test activities confirmed SSC operability and functional capability following maintenance. The inspectors reviewed the licensee's completed test procedures to ensure any of the SSC safety function 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 verified that PMT activities were conducted in accordance with applicable WO instructions, or procedural requirements, including NPG-SPP-6.3, Pre-/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: B EDG Six and Two Year Inspection, Overspeed Trip Limit Switch Replacement, and Governor Oil Tubing Modification PMT per WOs 111843937, 10565268, 112239413, and 3-SR-3.8.1.1(3B), Diesel Generator 3B Monthly Operability Test
- Units 1 and 2: A EDG Six and Two Year Inspection, Overspeed Trip Limit Switch Replacement, and Cylinders 8 and 18 Piston Replacements PMT per WOs 112244555 and 08-716769-001, and 0-SR-3.8.1.1(A), Diesel Generator A Monthly Operability Test
- Control Room Emergency Ventilation System PMT Per 0-SR-3.7.3.2 (HEPA), Control Room Emergency Ventilation System In Place Leak Test
- Unit 1: HPCI System Over-Pressurization and Booster Pump Outboard Seal Missing Setscrews Inspection and Repairs PMT per WOs 111985459, 112282753, 112238617, 112282108, and 1-SR-3.5.1.7(COMP), HPCI Comprehensive Pump Test
- Unit 1: RHR System Outboard Injection Valve 1-FCV-74-52 Repairs PMT per WO 112212918
- C3 EECW Pump Replacement PMT per WO 111972393; 3-SI-4.5.C.1(2), EECW Pump Operation; and, 0-SI-4.5.C.1(4), EECW System Annual Flow Rate Test.
- Unit 2: 250VDC Main Bank Battery No. 2 Replacement PMT per WO 08-716660-000, and 2-SR-3.8.4.3 (MB-2), Main Bank 2 Battery Service Test

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities

.1 Unit 2 Scheduled Refueling Outage (U2R16)

a. Inspection Scope

From February 26 through April 8, 2011, the inspectors examined critical outage activities associated with the U2R16 refueling outage and Unit 2 restart to verify that they were conducted in accordance with TS, applicable procedures, and the licensee's outage risk assessment and management plans. Refueling outage activities that occurred prior to April 1, 2011, were documented in NRC inspection report (IR) 05000260/2011002. Since April 1, the inspectors reviewed and examined selected refueling outage, unit startup and power ascension activities to ensure they were performed in accordance with approved procedures, TS requirements, and the licensee's outage risk control plan. Some of the more significant critical outage activities inspected were as follows:

- Monitored critical plant parameters, and operators control of plant conditions, during Cold Shutdown (Mode 4), Startup (Mode 2), and Power Operation (Mode 1) conditions

- Control and management of scheduled and emergent outage work activities, including impact on outage risk

- Witnessed portions of reactor startup and power ascension activities per General Operating Instruction (GOI) 2-GOI-100-1A, Unit Startup and Power Operation, including rod withdrawal for criticality, reactor coolant system heatup, synchronization of the main generator, and power ascension to full power

- Observed and verified reactor heatup and cooldown rate in accordance with 2-SR-3.4.9.1(1), Reactor Heatup and Cooldown Rate Monitoring; and 2-SR-3.4.9.1(2), Reactor Vessel Shell Temperature and Reactor Coolant Pressure During Monitoring Inservice Hydrostatic or Leak Testing.

Corrective Action Program

The inspectors continued to review daily PERs generated during U2R16 RFO, especially those designated as “Restart”. Resolution and implementation of specific corrective actions of selected PERs were also reviewed by the inspectors and discussed with responsible outage management.

b. Findings

No findings were identified.

.2 Three Unit Forced Outage Due to Loss of Offsite Power From Severe Storms and Automatic Reactor Scram

a. Inspection Scope

On April 27, 2011, all three Browns Ferry units automatically scrammed from a complete loss of the 500 KV offsite power grid system as a result of severe weather (see section 4OA3). All three units remained in Mode 4 (Cold Shutdown) conditions until the 500 KV electrical grid system was restored.

Operators commenced restart of Unit 1 (i.e., entered Mode 2) on May 19, followed by Mode 1 and main turbine generator synchronization on May 20, 2011. On May 24, the main turbine generator (MTG) was manually tripped due to an unisolable main steam leak on a first stage pressure instrument penetration. Following turbine repairs, the MTG was re-synchronized to the grid on May 26, and ascended to 96 percent RTP where reactor power was limited to 2200 MWe total due to grid instability. Unit 1 returned to 100 percent RTP on May 28, 2011.

Operators commenced restart of Unit 2 on May 23, followed by Mode 1 and main turbine generator (MTG) synchronization on May 24. Unit 2 ascended to 96 percent RTP on May 27 where reactor power was limited to 2200 MWe total due to grid instability. Unit 2 returned to 100 percent RTP on May 28, 2011.

Operators commenced restart of Unit 3 on May 31, followed by Mode 1 and MTG synchronization on the same day. Unit 3 returned to 100 percent RTP on June 4, 2011.

During the three unit forced outages, several operational transient events occurred that were observed and/or reviewed by the inspectors for impact on TS operability and any immediate safety concerns.

- On May 12, 2011, while in Mode 4, Unit 3 experienced a loss of shutdown cooling (SDC) for 40 minutes due to an inadvertent primary containment isolation system (PCIS) Group 2 actuation during Unit 3 PCIS relay replacement caused by inadequate work planning. Unit 3 reactor coolant temperature increased approximately 10 degrees Fahrenheit (F) until SDC was restored.
- On May 20, during power ascension from approximately 20 percent RTP, the suction side of the Unit 1 HPCI system was inadvertently over-pressurized during system venting due to a partially stuck open check valve (see report section 1R15 above). The Unit 1 HPCI system was promptly isolated and depressurized.
- On May 22, 2011, while in Mode 4, Unit 3 received a valid reactor protection system (RPS) full scram signal actuation due to high scram discharge volume (SDV) water level when operators improperly reset a prior invalid reactor scram received during instrument maintenance. All Unit 3 control rods were already fully inserted.

Licensee event reports (LER) pursuant to 10CFR50.73 were subsequently issued for each of the aforementioned events. These LERs will be reviewed, and appropriate regulatory actions taken, as part of the ROP baseline inspection program for LER follow-up.

During these forced outages the inspectors examined the conduct of critical outage activities pursuant to TS, applicable procedures, and the licensee's outage risk assessment and outage management plans. Some of the more significant outage activities monitored, examined and/or reviewed by the inspectors were as follows:

- Plant Oversight Review Committee (PORC) Unit 1 event review and restart meeting on May 16 and 17, 2011.
- PORC Unit 2 event review and restart meeting on May 13, 14 and 17, 2011.
- PORC Unit 3 event review and restart meeting on May 27 and 28, 2011.
- Review of Units 1, 2, and 3 Post Scram Reports (1/2/3-AOI-100-1, Attachments 1 and 2)
- Closeout inspection of the Unit 3 Drywell and review of 3-GOI-200-2, Primary Containment Initial Entry and Closeout on May 6, 2011 (Units 1 and 2 drywells were not entered)
- Reactor startup and power ascension activities per 1/2/3-GOI-100-1A, for all three Unit Startups

- Reactor vessel and coolant heatup per 1/2/3-SR-3.4.9.1(1), Reactor Heatup and Cooldown Rate Monitoring for all three Units
- Outage risk assessment and management
- Control and management of forced outage and emergent work activities

Corrective Action Program

The inspectors reviewed PERs generated during the Units 1, 2, and 3 forced outages and attended management review committee meetings to verify that initiation thresholds, priorities, mode holds, and significance levels were assigned as required.

b. Findings

No findings were identified regarding outage activities. However, the regulatory significance of operational transients that occurred during the multi-unit forced outage will be reviewed and determined as part of the routine baseline follow-up inspection of any related LERs.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed portions and/or reviewed completed test data for the following eight 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 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.

In-Service Tests:

- 2-SR-3.5.1.6(RHR II) - Quarterly RHR System Rated Flow Test – Loop II

Routine Surveillance Tests:

- 3-SR-3.8.1.1(3B), Diesel Generator 3B Monthly Operability Test
- 0-SR-3.7.3.4(A) Control Room Envelope Unfiltered Inleakage Test
- 1-SR-3.3.6.2.4(RX), Reactor Zone Isolation System Functional Test
- 3-SR-3.3.6.1.2(ATU B), Reactor Protection and Primary Containment Isolation Systems Analog Trip Unit Channel B1 Functional Test
- 0-SR-3.8.1.6, Common Accident Signal Logic Test
- 2-SR-3.4.3.2, Main Steam Relief Valves Manual Cycle Test

Reactor Coolant System Leak Detection Tests:

- 1-SR-3.4.5.2, Drywell Leak Detection Radiation Monitor Functional Test 1-RM-90-256

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

During the report period, the inspectors observed an Emergency Preparedness (EP) training drill that contributed to the licensee's Drill/Exercise Performance (DEP) and Emergency Response Organization (ERO) performance indicator (PI) measures on June 15, 2011, to identify any weaknesses and deficiencies in classification, notification, dose assessment and protective action recommendation (PAR) development activities. The inspectors observed emergency response operations in the simulated control room and certain Emergency Response Facilities to verify that event classification and notifications were done in accordance with EPIP-1, Emergency Classification Procedure and other applicable Emergency Plan Implementing Procedures. The inspectors also attended the licensee critique of the drill to compare any inspector-observed weakness with those identified by the licensee in order to verify whether the licensee was properly identifying weaknesses.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

Cornerstone: Mitigating Systems

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the following Performance Indicators (PIs), including procedure NPG-SPP-02.2, Performance Indicator Program. The inspectors examined the licensee's PI data for the specific PIs listed below for the second quarter of 2010 through the first quarter of 2011. The inspectors reviewed the licensee's data and graphical representations as reported to the NRC to verify that the data was correctly reported. The inspectors also validated this data against relevant licensee records (e.g., PERs, Daily Operator Logs, Plan of the Day, Licensee Event Reports, Maintenance Rule Cause Determination and

Evaluation Reports, etc.), and assessed any reported problems regarding implementation of 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 also used the Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, to ensure that industry reporting guidelines were appropriately applied.

- Unit 1 Safety System Functional Failures
- Unit 2 Safety System Functional Failures
- Unit 3 Safety System Functional Failures
- Unit 1 Mitigating Systems Performance Index - High Pressure Coolant Injection
- Unit 2 Mitigating Systems Performance Index - High Pressure Coolant Injection
- Unit 3 Mitigating Systems Performance Index - High Pressure Coolant Injection
- Unit 1 Mitigating Systems Performance Index - Reactor Core Isolation Cooling
- Unit 2 Mitigating Systems Performance Index - Reactor Core Isolation Cooling
- Unit 3 Mitigating Systems Performance Index - Reactor Core Isolation Cooling

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems

.1 Review of items entered into the Corrective Action Program:

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program (CAP). This review was accomplished by reviewing daily Service Request (SR) report summaries and periodically attending Corrective Action Review Board (CARB) and PER Screening Committee (PSC) meetings.

.2 Semiannual Review to Identify Trends

a. Inspection Scope

As required by Inspection Procedure 71152, the inspectors performed a review of the licensee's CAP implementation 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 trend reports and trending efforts, internal assessments and independent searches of the PER database and WO history. The review also included issues documented outside the normal CAP in Quick Human Error Analysis Tool (QHEAT) reports, and maintenance rule assessments. The inspectors' review nominally considered the six-month period of January 2011 through June 2011, although some searches expanded beyond these dates. Additionally, the inspectors' review included the Integrated Trend Reports (ITR) from the first and second quarters of fiscal year 2011, which covered the period of October 1, 2010 to March 31, 2011. Furthermore, the inspectors verified that adverse or negative trends identified in the licensee's PERs, periodic reports and trending efforts were entered into the CAP. Inspectors interviewed the appropriate licensee management and also reviewed procedures, NPG-SPP-02.8, Integrated Trend Review, Rev. 1 and NPG-SPP-02.7 PER Trending, Rev. 1.

b. Findings and Observations

No findings were identified, but the inspectors did identify a number of observations as discussed below.

The purpose of the licensee's integrated trend review process was to identify the top issues (gaps to excellence) requiring management attention. Other objectives of the ITR program were to provide status of the top issues and their progress to resolution; identify continuing issues, emerging trends and issues to be monitored; review progress towards resolving past top issues; and review issues identified by external organizations such as the NRC, Institute of Nuclear Power Operations, Nuclear Safety Review Board (NSRB), Quality Assurance (QA), etc., and determine why they were not identified by line organizations.

The following were the more significant trend issues identified by the licensee that were in both of the last two ITR's. These issues were verified by the inspectors to be in the CAP, and all associated PERs contained either ongoing or completed corrective actions.

- Inconsistent application of OPDP-1, Conduct of Operations, by Operations personnel (PER 335574). This issue was also identified by the QA organization as a Level 1 Escalation due to a lack of urgency and effectiveness by the Operations department in responding to and correcting this issue. Corrective actions were ongoing.
- Work package documentation issues have been identified by the licensee and other organizations. The licensee initiated PER 296609, for which the corrective actions have recently been completed.
- Weaknesses in engineering rigor were identified by the licensee as well as other organizations. PER 311715 was initiated on this issue and an Engineering Performance Improvement plan was developed.
- Deficiencies in work order instructions and technical procedures were identified by the licensee and other organizations. PER 243665 was initiated on this issue and corrective actions were ongoing.

The licensee identified that certain departments did not submit their inputs for the ITR on time, which contributed to both ITRs being issued late. The licensee initiated PER 371430 to address the overdue ITRs. The poor timeliness of the ITRs has been a persistently recurring issue for several years.

Inspectors noticed a number of repetitive trend issues (e.g., Individual accountability and reinforcement of standards for all OPS personnel, Work package documentation issues, Weaknesses in engineering vigor, Deficiencies in work order instructions) in both the first and second quarter ITRs. The inspectors reviewed these repeat issues to confirm the licensee was continuing to take appropriate actions to address the recurring trends.

The inspectors noted the licensee has made efforts to improve the trending process by adding additional PER trending codes, applying more consistent coding among PER's and also by applying additional statistical analysis to the process. The new PER coding methodology was started in the January – February timeframe and should provide clearer more useful results in upcoming ITR's.

The inspectors conducted an independent review of recent PERs, including those previously identified by the inspectors, to determine whether any other potential adverse trends existed. The inspectors identified two potential adverse trends which were not specifically captured in the licensee's CAP. The inspectors also provided the PER examples of these potential trends to the licensee. These potential adverse trends are described below.

A number of Operations-related human performance errors were recognized by the licensee and inspectors in 2011, particularly during the Unit 3 restart in January, the U2R16, and the three unit NOUE and forced outage. The majority of the PERs associated with these human performance errors were already captured by the licensee's B Level PER 335574 for inconsistent application of OPDP-1 standards, and the A Level PER 330400 regarding inadequate water level control. However, a number of the PERs identified by the inspectors were not included as part of the licensee's adverse trend on Operations standards (PER 335574), or the root cause rollup PER 330400. These omitted PERs primarily involved procedural use, adherence, and documentation (e.g., PERs 309223, 307617, 371725, 374948, 376872, 379528, 398609 and 407436). The inspectors reviewed these additional PERs, and their individual actions, in light of the licensee's more comprehensive corrective action plan for PER 335574 to verify whether they were adequately scoped within existing corrective actions. Although the PER 335574 corrective actions were directed towards improved standards and accountability, there were no specific actions to address an adverse trend in procedural use and adherence. In response to this potential trend identified by the inspectors, the licensee initiated PER 407109 to address the trending implications associated with procedural use and adherence.

In addition, the inspectors identified a number of PMT procedure and execution discrepancies that continued to represent an adverse trend in the implementation of PMTs (see also Section 4OA2 of IR 50-259, 260, and 296/2010-05). More specifically, the inspectors identified a number of PMT - related problems regarding the adequacy of PMT implementation (e.g., PER 372584, 382971, 399924 and 382375), and PMT documentation (e.g., PER 387154, 387156, 387163, and 382350). The licensee initiated PER 403920 on the potential adverse trend identified by inspectors. The inspectors also reviewed licensee efforts to address an adverse trend in work documentation problems (PER 296609). Corrective actions on PER 296609 were continuing.

4OA3 Event Follow-up

.1 Loss of Offsite Power Event and Three Unit Automatic Reactor Scram

a. Inspection Scope

On April 27, 2011, at about 1636 CDT, all three Browns Ferry units automatically scrammed from a complete loss of the 500 KV offsite grid system as a result of severe weather experienced in the surrounding area, including numerous tornadoes (none of which directly struck the site). All 500 KV and 161 KV offsite power supply lines were lost, except the 161 KV Athens line which remained in-service along with the A common service station transformer (CSST) supplying the 1A and 2A Start Buses. The sudden loss of all 500 KV offsite power sources caused near simultaneous main turbine generator trips and reactor scrams on all three units. Seven of eight EDGs started and loaded, except the 3B EDG that was OOS for planned maintenance. The licensee promptly declared and executed a Notice of Unusual Event (NOUE) for a loss of normal and alternate supply voltage to all 4 KV shutdown boards for greater than 15 minutes, and at least two EDGs supplying power to their unit specific 4 KV shutdown boards, in accordance with EPIP-1, Emergency Classification Procedure and EPIP-2, Notice of Unusual Event. All three units were depressurized and cooled down to Mode 4 (Cold Shutdown) conditions by April 28, 2011. The licensee terminated the NOUE on May 2, 2011 after restoring two 161 KV qualified offsite power sources, transferring all 4KV Shutdown Boards to offsite power, and placing all EDGs in standby. For the duration of the NOUE, the inspectors established and maintained continuous twenty-four hour inspection coverage to monitor plant parameters, operator actions, and safety equipment performance.

During the initial LOOP event on April 27, inspectors were in the main control room and witnessed Operations personnel response to the station loss of offsite power (LOOP) and scram of all three units. The resident inspectors verified that all three units were stabilized and maintained in Mode 3 (Hot Shutdown) conditions. The inspectors also confirmed that all safety-related mitigating systems and automatic functions operated properly for the current plant conditions. Furthermore, the inspectors evaluated safety equipment and operator performance during and after the event by examining existing plant parameters, annunciator alarms, instrument recorders, plant computer historical data displays, operator logs, and the critical parameter trend charts for all three units. The inspectors interviewed responsible on-shift Operations personnel and examined the implementation of applicable ARPs, AOIs, EOIs, and EPIPs, particularly 2-AOI-100-1, Reactor Scram. The inspectors also reviewed and verified that all NRC required notifications were made in accordance with 10 CFR 50.72.

The inspectors monitored licensee activities for depressurizing and cooling down all three units to Mode 4 (Cold Shutdown) in accordance with plant procedures, particularly the following:1/2/3-GOI-100-12A, Unit Shutdown from Power Operations to Cold Shutdown; 1/2/3-SR-3.4.9.1(1), Reactor Heatup and Cooldown Rate Monitoring; and applicable EOI appendices. Stable Mode 4 conditions, with seven of eight vital 4 KV shutdown boards being supplied by onsite EDGs, were established for all three units within 24 hours after the initial event.

During the five days following the initial LOOP event, until termination of the NOUE, several operational transients of varying significance occurred that were observed and/or reviewed by the inspectors as part of Event Follow-up inspection activities. The following events were examined by the inspectors for impact upon TS operability, immediate safety significance, and as potential significant operational events warranting further reactive inspection.

- On April 27, 2011, while in Mode 3, Unit 1 experienced an unplanned valid RPS full scram signal actuation due to operator error when reactor vessel water level (RVWL) inadvertently reached the low level scram setpoint. Control rods were already fully inserted at the time.
- On April 28, 2011, while Units 1 and 2 were in Mode 4, the licensee performed an emergency shutdown of the Unit 1/2 C EDG due to an EDG governor oil leak. Securing the C EDG resulted in an unexpected PCIS Group 2 actuation on Unit 1 which caused a loss of SDC for about 47 minutes; and, a momentary suspension of SDC on Unit 2 due to loss of power to the running 2B RHR pump until the 2D RHR was promptly started. Unit 1 reactor coolant temperature had increased about 30 F until SDC was restored; there was no appreciable increase in Unit 2 reactor coolant temperature.
- On May 2, 2011, while Unit 1 was in Mode 4, the output breaker of the Unit 1/2 A EDG tripped due to a malfunction of a mechanical overspeed switch. This failure of the A EDG resulted in an PCIS Group 2 actuation which caused another loss of SDC on Unit 1 similar to the April 28 event. Unit 1 SDC flow was lost for approximately 57 minutes until it was restored which resulted in an increase of reactor coolant temperature of about 24 F.

Licensee event reports (LER) pursuant to 10CFR50.73 were subsequently issued by the licensee for each of the aforementioned events. These LERs will be reviewed, and appropriate regulatory actions taken, as part of the ROP baseline inspection program for LER follow-up.

b. <u>Findings</u>

No findings were identified during the station LOOP and multi-unit scram. However, the regulatory significance of operational transients after the initial event will be reviewed and determined as part of the routine baseline follow-up inspection of associated LERs.

.2 <u>(Closed) LER 05000259/2010-005-00, and 05000259/2010-005-01, Safety Relief Valves As-Found Setpoints Exceeded Technical Specification Lift Pressure Values</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the LER dated February 4, 2011, and its revision dated April 1, 2011. The inspectors also reviewed the applicable PER 294506, including associated apparent cause determination and corrective action plans. The inspectors also reviewed the fuel vendor's evaluation 000-0127-2669-R0, Browns Ferry Nuclear Plant Unit 1 Cycle 8 Evaluation of As-Found SRV Opening Setpoints on Vessel Overpressure, dated January 4, 2011.

Following the U1R8 RFO, the licensee removed and lift tested the 13 MSRVs that had been in service during cycle 8 operation. During this surveillance testing, the as-found U1C8 lift setpoints for three of the 13 MSRVs exceeded the TS 3.4.3 allowed limit of plus three percent of the TS required setpoint. The causes of the MSRV as-found setpoints being above their TS limits were determined to be corrosion bonding between the pilot valve seat and disc (generic industry problem); and inconsistent laboratory test conditions. The licensee's corrective action plans included the continued use of platinum coated valves in the discs of all thirteen refurbished MSRV pilot cartridges that were installed in Unit 1 for cycle 9 operation; and revised administrative controls at the MSRV test facility.

The failure of these MSRVs to lift within the allowed setpoint limits constituted a condition prohibited by TS 3.4.3. To address the potential safety consequences, the licensee's fuel vendor conducted a reactor vessel overpressure evaluation by comparing the U1 Cycle 8 as-found MSRV lift setpoint data with the Cycle 7 data. From the results of this evaluation, the licensee concluded that the as-found condition of the MSRVs from Unit 1 Cycle 8 were bounded by the Cycle 7 as-found conditions and reactor vessel overpressure analyses. Consequently, the licensee determined that the Unit Cycle 8 as-found MSRV setpoints were sufficient to fulfill their overpressure relief safety function during the most limiting design basis over-pressure transient events, including an anticipated transient without scram (ATWS) overpressure event. This evaluation verified compliance with the Technical Specifications Safety Limit, ASME Upset Limit, and ASME Section III Service Level C Limit for emergency events.

b. Findings

One finding was identified by the licensee (see Section 4OA7 below). These LERs are considered closed.

.3 (Closed) LERs 05000259/2010-004-00, and 05000259/2010-004-01, Residual Heat Removal Low Pressure Injection System Pump Motor Failure

a. Inspection Scope

The inspectors reviewed the LER dated December 23, 2010, and its revision dated March 31, 2011. The inspectors also reviewed the applicable PER 274840, including associated apparent cause determination and corrective action plans.

On October 27, 2010, the 1C RHR pump motor suddenly seized (i.e., rotor to stator contact) while operating in the shutdown cooling mode. At the time, Unit 1 was in Mode 5 for the U1R8 refueling outage. Operators promptly placed the 1A RHR pump in service for shutdown cooling after the catastrophic failure of the 1C RHR pump. The 1C RHR pump motor was subsequently replaced prior to Unit 1 restart. The root cause was subsequently determined to be a bow in the rotor that was misdiagnosed and improperly treated as an imbalance condition during refurbishment of the 1C RHR motor for Unit 1 recovery.

The issues associated with this LER, and its revision, were previously addressed by the inspectors and documented in Section 1R20.1(2) of IR 05000259/2010005.

b. Findings

One finding was previously identified in IR 05000259/2010005 (see NCV 05000259/2010005-02). These LERs are considered closed.

.4 (Closed) LER 05000296/2010-003-02, Multiple Test Failures of Excess Flow Check Valves

a. Inspection Scope

The inspectors had previously reviewed the original LER, and revision number one. The inspectors had also reviewed applicable PERs 222850, 223215, and 241921, including associated apparent cause determination and corrective action plans. Furthermore, the inspectors had reviewed the Maintenance Rule (a)(1) ten point plan developed for the Units 1, 2, and 3 excess flow check valves (EFCV) as a result of the reported Unit 3 EFCV functional failures. The results of these reviews were documented in IR 05000296/2010004. Since then, the licensee submitted a second revision to LER 05000296/2010-003 in order to provide additional clarification, and information regarding their corrective actions to prevent recurrence. This second revision was reviewed by the inspectors, and no further regulatory actions were deemed necessary.

b. Findings

One finding was previously identified in IR 05000296/2010004, Section 4OA7. This LER is considered closed.

.5 (Closed) LER 05000259/2010-002-01, Drywell Pressure Instrument Channel Inoperability Due to Improper Instrument Tubing Slope

a. Inspection Scope

The inspectors reviewed the original LER and revision one of this LER. The latest revision was considered administrative in nature to provide consistent instrument nomenclature and correct event dates.

On September 16, 2010, the licensee determined that a condition initially identified on December 8, 2008, resulted in the inoperability of a drywell pressure channel instrument for longer than allowed by TS. This LER actually described two events in which two separate drywell pressure instruments were inoperable longer than allowed by the TS. The first event was associated with instrument 1-PT-064-56C. The licensee determined that this instrument was inoperable from October 2, 2008, to December 9, 2008. However, during this time Unit 1 was shutdown between October 25 and November 30, 2008. For the period of applicable channel inoperability, the licensee did not meet TS Limiting Condition of Operation (LCO) 3.3.1.1, Reactor Protection System Instrumentation; 3.3.6.1, Primary Containment Isolation System Instrumentation; 3.3.6.2

Secondary Containment Isolation System Instrumentation; and 3.3.7.1 Control Room Emergency Ventilation System Instrumentation. The second event was associated with instrument 1-PIS-064-56B. The licensee determined that this instrument was inoperable from May 25, 2010 to October 6, 2010. During this channel inoperability, the licensee failed to meet TS LCOs 3.3.1.1; 3.3.6.1; 3.3.6.2; 3.3.7.1; 3.3.3.1, Post Accident Monitoring Instrumentation and 3.3.3.2 Backup Control System.

For both events, the licensee determined the direct cause was due to an improper instrument line slope that allowed water to accumulate in the sensing line which resulted in a non-conservative biased instrument output. The root cause of the improperly sloped instrument sensing lines was the licensee's failure to adhere to engineering specification N1E-003, Instrument and Instrument Line Installation and Inspection. Corrective actions included a blowdown of the affected instrument line to remove the entrained water. Also, a design change was implemented during the most recent refueling outage which re-routed the affected instrument sensing line to eliminate the water traps in accordance with engineering specification N1E-003.

b. Findings

Two findings were previously identified in IR 05000259/2011002, Section 4OA7. This LER is considered closed.

4OA5 Other Activities

.1 (Closed) NRC Temporary Instruction 2515/183, "Followup to the Fukushima Daiichi Nuclear Station Fuel Damage Event"

a. Inspection Scope

The inspectors assessed the activities and actions taken by the licensee to assess its readiness to respond to an event similar to the Fukushima Daiichi nuclear plant fuel damage event. This included (1) an assessment of the licensee's capability to mitigate conditions that may result from beyond design basis events, with a particular emphasis on strategies related to the spent fuel pool, as required by NRC Security Order Section B.5.b issued February 25, 2002, as committed to in severe accident management guidelines, and as required by 10 CFR 50.54(hh); (2) an assessment of the licensee's capability to mitigate station blackout (SBO) conditions, as required by 10 CFR 50.63 and station design bases; (3) an assessment of the licensee's capability to mitigate internal and external flooding events, as required by station design bases; and (4) an assessment of the thoroughness of the walkdowns and inspections of important equipment needed to mitigate fire and flood events, which were performed by the licensee to identify any potential loss of function of this equipment during seismic events possible for the site.

b. Findings

Inspection Reports 05000259, 260 & 296/2011009 (ML111330509) documented detailed results of this inspection activity. Following issuance of the report, the inspectors conducted detailed follow-up on selected issues. No findings were identified during this follow-up inspection.

.2 (Closed) NRC Temporary Instruction 2515/184, "Availability and Readiness Inspection of Severe Accident Management Guidelines (SAMGs)"

On May 27, 2011, the inspectors completed a review of the licensee's severe accident management guidelines (SAMGs), implemented as a voluntary industry initiative in the 1990's, to determine (1) whether the SAMGs were available and updated, (2) whether the licensee had procedures and processes in place to control and update its SAMGs, (3) the nature and extent of the licensee's training of personnel on the use of SAMGs, and (4) licensee personnel's familiarity with SAMG implementation.

The results of this review were provided to the NRC task force chartered by the Executive Director for Operations to conduct a near-term evaluation of the need for agency actions following the Fukushima Daiichi fuel damage event in Japan. Plant-specific results for the Browns Ferry Nuclear Plant were provided as an Enclosure to a memorandum to the Chief, Reactor Inspection Branch, Division of Inspection and Regional Support, dated June 02, 2011 (ML111530328).

.3 (Opened) Unresolved Item (URI), Use of Inappropriately Qualified Methods to Evaluate Emergency Core Cooling System During Accident Mitigation

Introduction: The inspectors identified an URI associated with the emergency core cooling system (ECCS) evaluation performed for the Units 2 and 3.

Description: The inspectors reviewed Calculation ANP-2908(P), "Browns Ferry Units 1, 2, and 3 105% OLTP LOCA Break Spectrum Analysis." The inspectors determined that the analysis, which used the ECCS Evaluation Model described in EMF-2361(P)(A), "EXEM BWR-2000 ECCS Evaluation Model" was not an adequate evaluation for application at Browns Ferry. The Browns Ferry ECCS evaluation was somewhat unique for two reasons: (1) In most BWR cases, the ADS was single failure-proof; however, for Browns Ferry it was not, and (2) The most severe postulated loss of coolant accidents (LOCA) for Browns Ferry were those arising from small breaks, rather than a large break. Therefore, certain aspects of the approved evaluation model were not applicable to the unique plant configuration at Browns Ferry. Because of this, the evaluation model described in EMF-2361(P)(A) was not entirely applicable to Browns Ferry while the ADS system design was considered to be non-single-failure-proof. Dialog with the licensee and vendor have identified the staffs concerns and resolutions were being pursued through inspection efforts with the licensee and fuel vendor.

Summary: This issue is unresolved pending completion of fuel vendor inspection efforts. The URI for this issue is identified as 05000259, 260, and 296/2011003-3, Use of Inappropriately Qualified Methods to Evaluate the Emergency Core Cooling System.

4OA6 Meetings, Including Exit

.1 Exit Meeting Summary

On July 8, 2011, the resident inspectors presented the inspection results to Mr. Keith Polson, Site Vice President, and other members of the licensee's staff, who acknowledged the findings. The inspectors also conducted a follow-up exit meeting with Mr. Polson and his staff on July 29, 2011. All proprietary information reviewed by the inspectors as part of routine inspection activities were properly controlled, and subsequently returned to the licensee or disposed of appropriately.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which met the criteria of the NRC Enforcement Policy, for being dispositioned as a Non-Cited Violation.

- Unit 1 Technical Specification 3.4.3, Safety/Relief Valves, required that twelve of thirteen main steam safety relief valves (MSRVs) lift at a setpoint within plus or minus three percent of a specified value. Contrary to this, during TS required surveillance testing following the Unit 1 Cycle 8 refueling outage, the licensee discovered that the lift setpoints of three MSRVs exceeded the plus three percent TS allowed pressure band. This TS violation was entered into the licensee's CAP as PER 294506. The finding was determined to be of very low safety significance because the as-found lift setpoint conditions of the Unit 1 MSRVs were evaluated and determined to meet the design basis criteria for the most limiting reactor pressure vessel over-pressurization events.

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee
W. Baker, Operations Support Superintendent
S. Bono, Maintenance Manager
J. Boyer, Systems Engineering Manager
O. Brooks, Operations LOR Supervisor
B. Bruce, Nuclear Steam Supply Systems Engineering Manager
W. Byrne, Site Security Manager
J. Colvin, Engineering Programs Manager
P. Donahue, Assistant Engineering Director
G. Doyle, Assistant to the Site Vice President
M. Durr, Director of Engineering
M. Ellet, Maintenance Rule Coordinator
J. Emens, Licensing Manager
A. Feltman, Emergency Preparedness Manager
N. Gannon, Plant General Manager
K. Groom, Mechanical Design Engineering Supervisor
D. Hughes, Operations Manager
D. Jarrell, Operations Training Supervisor
M. Keck, Reactor Engineering Manager
S. Kelly, Assistant Work Control Manager
D. Kettering, I&C and Electrical Systems Engineering Manager
R. King, Design Engineering Manager
D. Malinowski, Operations Training Manager
T. Marlow, Director of Safety and Licensing
M. McAndrew, Assistant Operations Manager
J. Morris, Director Training
R. Norris, Radiation Protection Manager
W. Nurnberger, Work Control Manager
W. Pearce, Performance Improvement Manager
K. Polson, Site Vice President
M. Rasmussen, Operations Superintendent
H. Smith Fire Protection Supervisor
T. Smith, Component Engineering Manager
J. Underwood, Chemistry Manager
A. Yarbrough, BOP Engineering Supervisor

## LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

| | | |
|---|---|---|
| 05000259, 260, 296/2011003-03 | URI | Use of Inappropriately Qualified Methods to Evaluate Emergency Core Cooling During Accident Mitigation (Section 4OA5.3) |

Opened and Closed

| | | |
|---|---|---|
| 05000259, 260, 296/2011003-01 | NCV | Failure to Take Corrective Actions to Preclude a Repetitive Functional Failure of an EDG due to Excessive Heat Exchanger Fouling (Section 1R07) |
| 05000259/2011003-02 | NCV | Over-Pressurization of High Pressure Coolant Injection System due to Stuck Open HPCI System Testable Check Valve (Section 1R15) |
| 05000259, 260, 296/2515/183 | TI | Follow-up to the Fukushima Daiichi Nuclear Station Fuel Damage Event (Section 4OA5.1) |
| 05000259, 260, 296/2515/184 | TI | Availability and Readiness Inspection of Severe Accident Management Guidelines (SAMGs) (Section 4OA5.2) |

Closed

| | | |
|---|---|---|
| 05000259/2010-005-00 | LER | Safety Relief Valves As-Found Setpoints Exceeded Technical Specification Lift Pressure Values (Section 4OA3.2) |
| 05000259/2010-005-01 | LER | Safety Relief Valves As-Found Setpoints Exceeded Technical Specification Lift Pressure Values (Section 4OA3.2) |
| 05000259/2010-004-00 | LER | Residual Heat Removal Low Pressure Injection System Pump Motor Failure (Section 4OA3.3) |
| 05000259/2010-004-01 | LER | Residual Heat Removal Low Pressure Injection System Pump Motor Failure (Section 4OA3.3) |
| 05000296/2010-003-02 | LER | Multiple Test Failures of Excess Flow Check Valves (Section 4OA3.4) |
| 05000259/2010-002-01 | LER | Drywell Pressure Instrument Channel Inoperability Due to Improper Instrument Tubing Slope (Section 4OA3.5) |

Discussed

None

## LIST OF DOCUMENTS REVIEWED

**Section 1R01: Adverse Weather Protection**

OPDP-2, Switchyard Access and Switching Order Execution, Rev. 06
0-GOI-300-4, Switchyard Manual, Rev. 82
0-GOI-300-4, Attachment 1, General Information for Switchyard Operations, Rev. 75
IGA-6, Policy and Organization Manual Intergroup Agreement Power System Operations, Rev. 13
TRO-TO-SPP-30.100, Annual Nuclear Offsite Power (NOP) Operating Transmission System Studies Review, Rev. 04
TRO-TO-SOP-30.101, Nuclear Offsite Power Disqualification Notification and Call-Out Procedure, Rev. 08
TRO-TO-SOP-30.128, Browns Ferry Nuclear Plant (BFN) Grid Operating Guide, Rev. 12
TRO-TO-SOP-10.328, Nuclear Offsite Power Disqualification Notification and Call-Out Procedure, Rev. 7
SPP-7.1, On-Line Work management, Rev. 16
BFN-50-7200F, Plant Offsite Power Distribution System General Design Criteria Document, Rev. 07
NOM-SDP-6-Switchyard Risk (SYR), Nuclear Switchyard Risk, Rev. 02
TRA-BA-SPP-30.327, Downpowering of Nuclear Units Under Low System Load Conditions, Rev. 06
PSO-SPP-10.303, System Alerts, Rev. 05
TOM-NOM-SPP-06.001, TOM Nuclear Switchyard Risk (SYR), Rev. 06
Response to Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power, April 3, 2006
SR 388783 cracked concrete base pads on switchyard towers
SR 388796 gaps identified on the 1A USST bus duct cover
SR 387021 switchyard vehicular gate found unlocked

**Section 1R04: Equipment Alignment**

1-OI-74, Residual Heat Removal System, Rev. 74
1-47E811-1, Flow Diagram Residual Heat Removal System, Rev 35
1-47E610-74-1A, Mechanical Control Diagram Residual Heat Removal System, Rev. 29
SR 368054, Card placed by procedure for shutdown cooling was not in place.
3-OI-82/Att-1B, Standby Diesel Generator 3B Valve Lineup Checklist, Rev. 97
3-OI-82/Att-2B, Standby Diesel Generator 3B Panel Lineup Checklist, Rev. 97
3-OI-82/Att-3B, Standby Diesel Generator 3B Electrical Lineup Checklist, Rev. 96
2-SR-3.8.4.4(MB-2), Main Bank 2 Battery Modified Performance Test, Rev. 20
0-OI-57D/Att-3A, DC Distribution Electrical Lineup Checklist Unit 1, Rev. 121
0-OI-57D/Att-3C, DC Distribution Electrical Lineup Checklist Unit 3, Rev. 121

**Section 1R05: Fire Protection**

Fire Pre-Plan No. RX1-565, Rev. 8
Fire Pre-Plan No. RX1-593, Rev. 8
0-SI-4.11.G.2.b, Fire Door Inspection, Rev. 18
0-SI-4.11.G.1.a, Visual Inspection of Fire Rated Barriers (Floors, Walls, & Ceiling), Rev. 19
0-SI-4.11.E.1.A, Inspection and Reracking of Fire Hose Stations, Rev. 16
Fire Hazards Analysis, Fire Zone 1-3, Rev. 9
Fire Hazards Analysis, Fire Zone 1-4, Rev. 9
SR 353799, BFN-1-DOOR-260-0221 needs to have the gasket seal replaced again on the knob side
Fire Pre-Plan No. RX1-565, Rev. 8
Fire Pre-Plan No. RX1-593, Rev. 8

0-SI-4.11.E.1.A, Inspection and Reracking of Fire Hose Stations, Rev. 16
Fire Hazards Analysis, Fire Zone 1-5, Rev. 9
Fire Hazards Analysis, Fire Zone 1-5, Rev. 9
SR 382956, revision required to fire pre-plans
Fire Protection Report Vol. 1, Rev. 9
Fire Protection Report Vol. 2, Pre-Plan No. RX2-519, Rev. 7
Fire Protection Report Vol. 2, Pre-Plan No. RX2-519NE, Rev. 7
Fire Protection Report Vol. 2, Pre-Plan No. RX2-519SE, Rev. 7
Fire Protection Report Vol. 2, Pre-Plan No. RX2-565, Rev. 9
0-SI-4.11.G.2, Semiannual Fire Door Inspection, Rev. 22
All Open Fire Protection Impairment Permits for Unit 2
WO 112165577, Minor Maintenance for Door BFN-2-DOOR-260-0242
WO 112197381, Repair Hanging Light at Fire Penetration
SR 385182, Inspection of Bulk Head Door Seals by 0-SI-4.11.G.2
PER 358896, Hanging Light at Fire Penetration

**Section 1R07: Heat Sink Performance**
0-OI-67, Emergency Equipment Cooling Water System, Rev. 93
0-TI-522, Program for Implementing NRC Generic Letter 89-13, Rev. 0
0-TI-389, Raw Water Fouling and Corrosion Control, Rev. 13
3-SI-3.2.4(DG D), EECW Valve Test on Diesel Generator D, Rev. 3
NPG-SPP-09.14, Generic Letter (GL) 89-13 Implementation, Rev. 0
3-47E859-1, Flow Diagram Emergency Equipment Cooling Water, Rev. 38
3-47E859-2, Flow Diagram Emergency Equipment Cooling Water, Rev. 24
0-47E839-5, Flow & Control Diagram Raw Water Chemical Treatment System, Rev. 15
0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting - 10CFR50.65, Rev. 35
NEDP-12, Equipment Trending Attachment 1 for PER 211737, Rev. 11
Past Operability Determination for Low EECW flow to 3D DG HX - PER 381569, July 1, 2011
PER 243132, D DG HX Functional Failure due to Excessive Fouling, July 16, 2010
Justification for Deferral of Degraded or Non-Conforming Conditions for U2R16 Refuel Outage, NPG-SPP-03.1.7, March 1, 2011
SR 396425, Diesel Generator A EECW flow check per 0-OI-67
SR 387385, 3B DG HEXs have excessive fouling as noted during raw water inspection
PER 381569, 3D Diesel Generator Inoperable due to low EECW flow
Functional Evaluation for PER 213088, Rev. 1
SR 385587, Unplanned LCO entry due to 3C DG Inoperable
SR 382121, 3D DG Heat Exchanger fouled
SR 385892, 3C DG Heat Exchanger fouled
CI-137, Raw Water Chemical Treatment, Rev. 20
CI-137.5, Raw Water Chemical Treatment Molluscicide Control, Rev. 31
NPG-SPP-03.1.4, Corrective Action Program Screening and Oversight, Rev. 2
NPG-SPP-09.18.2, Equipment Reliability Classification, Rev. 1
NPG-SPP-03.1, Corrective Action Program, Rev. 1
NPG-SPP-02.9, CAP Health Monitor, Rev. 2
NPG-SPP-03.1.13, Corrective Action Program Basis, Rev. 1
NPG-SPP-03.1.9, PER Closure, Rev. 1

**Section 1R11: Licensed Operator Requalification**

OPL177.041, H2 Supply Alarm, HPCI Pressure Switch Failure, Condenser Tube Leak, Fuel Failure, Maine Steam Line Leak, Un-isolable RCIC Steam Line Break, HPCI Failure, 2 Area Rad Levels Above Max Safe.
NPG-SPP-10.0, Plant Operations, Rev. 0
OPDP-1, Conduct of Operations, Rev. 19

**Section 1R12: Maintenance Effectiveness**

0-TI-267, Fuel Reliability Program, Rev. 24
0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting – 10CFR50.65, Rev. 35
Browns Ferry Nuclear Plant Foreign Material Exclusion (FME) Improvement Plan, Rev. 0
FSAR Section 3.2, Fuel Mechanical Design, BFN-23
Operational Decision-Making Issue (ODMI) Evaluation Document, Unit 3 Cycle 15 Fuel Failure, dated 9/29/10
PER 245792, Potential Fuel Leak on Unit 3
PER 245834, Indication of Fuel Leak Not Recognized
Technical Specifications and Bases 3.4.6, RCS Specific Activity, Amendment 244 and Rev. 29
Unit 3 Function 329a-b (a)(1) Plan, Rev 0, Effective Date 10/18/10
CDE 1012
0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting – 10CFR50.65, Rev. 35
Maintenance Rule Expert Panel Meeting Agenda, June 16, 2011
Maintenance Rule SSC/Function Record for Functions 575, 575-B, 575-D, 575-E
4kV Power Supply and Busses (a)(1) Plan, Rev. 0
MR unreliability data for 4kV Power Supply and Busses System 575, June 2009 – June 2011
MR unavailability data for 4kV Power Supply and Busses System 575, June 2009 – June 2011
PER 322640
PER 344287

**Section 1R13: Maintenance Risk Assessments and Emergent Work Control**

PRA Evaluation Response BFN-0-11-036, Rev. 1
Outage Risk Assessment Report F001 Outage, dated 5/04/11
PRA Evaluation Response BFN-0-11-050, Rev. 1
NPG-SPP-07.1, On Line Work Management, Rev. 3
NPG-SPP-09.11.1, Equipment Out of Service (EOOS) Management, Rev. 0
0-TI-367, BFN Equipment to Plant Risk Matrix, Rev. 11
EOOS Operator's Risk Report, June 3, 2011
NPG-SPP-09.11.1, Equipment Out of Service (EOOS) Management, Rev. 01
NPG-SPP-09.11, Probabilistic Risk Assessment (PRA) Program, Rev. 01
MCR logs
EOOS Operator's Risk Report, June 13 & 14, 2011
NPG-SPP-09.11.1, Equipment Out of Service (EOOS) Management, Rev. 01
NPG-SPP-09.11, Probabilistic Risk Assessment (PRA) Program, Rev. 01
MCR logs
BFN-0-11-054, PRA Evaluation Response 6/12-6/19/2011, Rev. 1

**Section 1R15: Operability Evaluations**
PER 365041, Collar on HPCI Booster Pump Missing Set Screws
WO 112238617, U1 HPCI Booster Pump Outboard Seal is Missing Set Screws
MCI-0-073-PMP002, Maintenance of the High Pressure Coolant Injection Booster Pump, Rev. 18
Unit 1 Technical Specification 3.5.1, ECCS – Operating
PER 287142, HPCI Testable Check Valve Fails to Test
PER 287591, HPCI Testable Check Valve Binding
PER 289169, 1-FCV-073-0045 Testable Check Valve Actuator Shows Open with the Valve Closed
PER 372838, Troubleshoot Unit 1 HPCI Testable Check Valve, 1-CKV-73-45
PER 372659, HPCI Gland Seal Condenser Leaking
WO 09-711620-000, Determine Cause on Binding on HPCI System Testable Check Valve
WO 112282474, TACF 1-11-002-073 Disconnect Actuator and Manually Stroke Valve Disc and Actuator on 1-FCV-073-0045
1-SR-3.6.1.3.5(SD), Valves Cycled During Cold Shutdown, Rev. 12
Unit 1 Technical Specification 3.5.1, ECCS – Operating
Unit 1 Technical Specification 3.6.1.3, Primary Containment Isolation Valves (PCIVs)
BFN-50-7073, High Pressure Coolant Injection Design Criteria
UFSAR Chapter 6, Emergency Core Cooling Systems
O-TI-248, Station Reactor Engineer, Rev. 89
U2 RCP 110414-000, Urgent Load Reduction/Recirc Pump Trip Contingency Plan
U3 RCP 110601-000, Unit 3 Tornado Scram Recovery
2-SR-2, Instrument Checks and Observations, Rev. 72
3-SR-2, Instrument Checks and Observations, Rev. 69
Functional Evaluation for PER 348160, Revs 0 and 1
Functional Evaluation for PER 348160, 379480, 379469, Rev. 2
PER 348160
PER 379469
PER 379480
0-TI-362, Inservice Testing of Pumps and Valves, Rev. 26
0-TI-443, Condition Monitoring of Check Valves, Rev. 6
1-SI-3.2.10, Verification of Remote Position Indicators for ASME Section XI Valves, Rev. 1
1-SI-4.7.A.2.g-3/3a, Primary Containment Local Leak Rate Test Reactor Feedwater Line A: Penetration X-9A, Attachment 2, System Isometric, Rev. 4
1-SR-3.6.1.3.5(SD), Valves Cycled During Cold Shutdown, Rev. 12
ASME OMa Code-1996 Addenda to ASME OM Code-1995 Code for Operation and Maintenance of Nuclear Power Plants
CM Plan ID: CMP-16, Condition Monitoring of Check Valves 1/2/3-FCV-73-45, Rev. 1
Drawing 52007-A, WEIR, 14-900 W.E. Testable Check Valve Air Cyl & Lim SW's
Drawing 1-47E812-1, Unit 1 High Pressure Coolant Injection System Flow Diagram, Rev. 29
FSAR Section 5.2.3.5, Isolation Valves, BFN-23
FSAR Section 6.0, Emergency Core Cooling Systems, BFN-22
NUREG 1482, Guidelines for Inservice Testing at Nuclear Power Plants, Rev. 1
PER 287142, HPCI Testable Check Valve Fails to Test
PER 287591, HPCI Testable Check Valve Binding
PER 289169, 1-FCV-73-45 Testable Check Valve Actuator Shows Open with the Valve Closed
PER 359841, Unit 2 HPCI Pump Suction Pressure High in Alarm
PER 372659, Unit 1 HPCI Gland Seal Condenser Leaking (re: Over-pressurization)
PER 372838, Minor Maintenance to Troubleshoot the Unit 1 HPCI Testable Check Valve 73-45

PER 380365, 1-FCV-73-45 Inappropriate Removal from Outage Scope
PER 387112, Reinstall 1-FCV-73-45 Actuator Arm
PER 394216, CARB Rejected ACE for PER 372659
PER 397698, Evaluate to Determine Design Location for 73-45 Light Changeover
Saphire SDP Runs dated June 29 and 30, 2011 for Unit 1 HPCI Testable Chk Vlv 73-45
Technical Specifications and Bases 3.5.1, ECCS – Operating, Amendment 269 and Rev. 53 respectively
Technical Specifications and Bases 3.6.1.3, Primary Containment Isolation Valves (PCIVs), Amendment 277 and Rev. 43 respectively
Temporary Alteration Control Form (TACF) 1-11-002-073, U1 HPCI System Testable Check Vlv, BFN-1-FCV-73-45
WO 09-711620-000, Determine Cause of Valve Binding of 73-45
WO 111665713, 1-FCV-73-45 HPCI Testable Check Valve Binding
WO 112282474, BFN-1-FCV-73-45, Disconnect Actuator and Manually Stroke Disc 73-45
WO 112288131, Implement TACF 1-11-002-073, Remove Actuator Arm Assembly from 73-45

**Section 1R18: Plant Modifications**
0-SR-3.8.1.6, Common Accident Signal Logic, Rev. 20
WO# 111672614
NPG-SPP-09.4, 10 CFR 50.59 Evaluations of Changes, Tests, and Experiments, Rev. 1
NPG-SPP-09.5, Temporary Alterations, Rev. 0
MMDP-1, Maintenance Management System, Rev. 20
TACF 1-11-002-073, U1 HPCI System Testable Check Valve
WO 112282474, TACF 1-11-002-073 Disconnect Actuator and Manually Stroke Valve Disc and Actuator on 1-FCV-073-0045
Unit 1 Technical Specification 3.5.1, ECCS – Operating
Unit 1 Technical Specification 3.6.1.3, Primary Containment Isolation Valves (PCIVs)

**Section 1R19: Post-Maintenance Testing**
3-SI-4.9.A.1.d(3B), Diesel Generator 2 Year Inspection
3-SR-3.8.1.1(3B), Diesel Generator 3B Monthly Operability Test, Rev. 40
MPI-0-082-INS004, Standby Diesel Engine Six Year Inspection
WO 09-716800-000, Sight Glass on Left Bank Air Line Lubricator for Start Motor
WO 09-726730-000, DG Cooler ECT
WO 09-726837-000, PM – Calibration of Fuel Oil Day Tank Level Switches
WO 10565268, DG 2 Year Inspection
WO 10573163, Left Bank Air Header Blowdown Valve Leak
WO 111843937, Standby Diesel Engine 6 Year Inspection
WO 111969221, Replace of 125 VDC Battery Terminal Cables
WO 112033032, 7 Day Fuel Oil Tank Vent Inspection and Cleaning
WO 112235198, Troubleshoot 3B DG OTLS Alarm Circuit
WO 112239413, Replace OTLS
0-SR-3.8.1.1(A), Diesel Generator A Monthly Operability Test, Rev. 41
1/2-SI-4.9.A.1.d(A), Diesel Generator A 2 Year Inspection, Rev. 48
MCI-0-082-PAC001, Standby Diesel Engine Power Pack Replacement, Rev. 1
MPI-0-082-INS004, Standby Diesel Engine Six Year Inspection, Rev. 49
0-TI-230V, Vibration Program, Rev. 7
WO 1110749, Replace Obsolete D/G Speed Switches for SDG A

WO 112244555, Replace 0-ENG-082-000A DG Cylinder 18 & 8 Piston
WO 112264606, A DG Stop Sequence Failure
WO 08-716769-001, PMT for D/G Speed Switch Replacement
0-SR-3.7.3.2 (HEPA), Control Room Emergency Ventilation System In Place Leak Test, Rev. 8
Work Order #112224397, Replace CREV Common HEPA Filter
Browns Ferry Nuclear Plant UFSAR, Section 10.12, Heating, Ventilating and Air-Conditioning Systems
1-SR-3.5.1.7(COMP), HPCI Comprehensive Pump Test, Rev. 17
1-OI-73, High Pressure Coolant Injection System, Rev. 19
PER 378724, HPCI Coupling Guard Rubbing
PER 377771, Unresponsive U1 HPCI Turbine Trip Upon System Startup and Coupling Rub
PER 377833, U1 HPCI Failed to Trip, Solenoid Change Out
PER 377052, Unplanned LCO Entry, EOI-2 & 3 Entries during HPCI Run
SR 386239, WO 111985459 operations signature for removal of clearance was not signed
SR 386256, Daughter WO 112304168 Post Work Reviews/Closeout not signed by operations
SR 386269, WO 112238617 PMT 1-SR-3.5.1.7 incorrect surveillance signed as performed
SR 386276, WO 112282360 Incorrectly referenced PMT
SR 386308, WO 112282364 PMT not performed with inadequate explanation
SR 377094, High Vibrations Identified on U1 HPCI Main and Booster Pumps
SR 378962, HPCI Pump on Doubled Test Frequency Due to High Vibes
SR 378310, 60 dpm Leak from U1 Turbine Exhaust Line Flanged Connection
SR 378296, U1 HPCI Main Pump Suction Flange Leak at 80 dpm
WO 111985459, U1 HPCI Alignment Check
WO 112286104, Cooling Water Line PRV
WO 112238617, U1 HPCI Booster Pump Outboard Seal Missing Setscrews
WO 112282753, Disassemble and Inspect U1 HPCI Gland Seal Condenser
WO 112286087, Collateral Damage Inspection of HPCI Pump Suction Relief
WO 112248176, Install and Remove HPCI Spool Piece
WO 112282108, Examine HPCI Instruments That May Be Damaged Due to 73-45 Failure
Work Order: 112212918, Disassemble/Inspect and if necessary install gussets per EDC 70296
Work Order: 112212646, Perform the required maintenance necessary to support MMG on rework of 1-FCV-074-0052
Design Change Notice, Engineering, EDC 70296 – weld modification to valve disc and skirt, Rev. A
LCOTR # 1-074-TS-2011-0202, Limiting Condition of Operations Tracking Log
MCR Operating Logs
1-OI-74, Residual Heat Removal System, Rev. 75
MCI-0-000-ACT0009, Maintenance of Limitorque Actuator Model SMB-5T, Rev. 27
MCI-0-000-PCK001, Generic Maintenance Instructions for Valve Packing, Rev. 24
MCI-0-074-VLV008, Maintenance of RHR Motor Operated Valves FCV-74-52 and 74-66, Rev. 16
PER 372584, Incorporate IST lesson learned into Unit 3 FCV-74-52/66 work orders
1-SR-3.6.1.3.5(RHR I), RHR System MOV Operability Loop I, Rev. 06
ECI-0-000-MOV009, Testing of Motor Operated Valves using MOVATS Universal Diagnostic System (UDS) and Viper 20, Rev. 23
WO 111972393, C3 EECW Pump Replacement
MCI-0-023-PMP001, Emergency Equipment Cooling Water … Removal and Reinstallation
3-SI-4.5.C.1(2), EECW Pump Operation
0-SI-4.5.C.1(4), EECW System Annual Flow Rate Test.
0-TI-345(EECW), EECW Pump Curve Data Acquisition

WO 08-716660-000, 250VDC Main Bank Battery No. 2 Replacement
2-SR-3.8.4.3 (MB-2), Main Bank 2 Battery Service Test
ECI-0-248-BAT005, 250VDC Main Bank 1, 2, and 3 Battery Cell Replacement
ECI-0-248-BAT001, Equalize Charging the 250 Volt Main Bank Batteries
2-SR-3.8.6.2(2), Quarterly Check of 250 VDC Main Bank Number 2 Battery

**Section 1R22: Surveillance Testing**
SR 384694: Delay for SR results in lengthy inoperable period
SR 385093: 2-SR-3.5.1.6 (RHR II) does not have an AC step to correlate with TS requirements
PER 387842, 2-SR-3.5.1.6 (RHR II) does not have an AC step to correlate with TS requirements
2-SI-3.1.2, RHR Pump Performance, Rev. 15
3-SI-3.1.2, RHR Pump Performance, Rev. 06
1-SR-3.5.1.6(RHR I), Quarterly RHR System Rated Flow Test Loop I, Rev. 19
2-SR-3.5.1.6(RHR I), Quarterly RHR System Rated Flow Test Loop I, Rev. 37
3-SR-3.5.1.6(RHR I), Quarterly RHR System Rated Flow Test Loop I, Rev. 38
3-SR-3.5.1.6(RHR II), Quarterly RHR System Rated Flow Test Loop II, Rev. 33
BFN-50-7074, Design Criteria Document for Residual Heat Removal System, Rev. 20
3-SR-3.8.1.1(3B), Diesel Generator 3B Monthly Operability Test, Rev. 40, completed May 8, 2011
Technical Specifications and Bases 3.8.1.1 AC Sources - Operating, Amendment 257 and Rev. 57 respectively
Technical Specifications and Bases 3.8.1.2 AC Sources - Shutdown, Amendment 257 and Rev. 52 respectively
FSAR Section 8.5, Standby AC Power Supply and Distribution, BFN-23
0-47E200-12-1, Control Bay Habitability Zone (CBHZ) Boundary, Rev. 01
0-TI-272, Control Bay Habitability Zone Penetration Breach Analysis, Rev. 11
0-TI-272, Control Bay Habitability Zone Penetration Breach Analysis, Rev. 12
0-OI-31, Control Bay and Off-Gas Treatment Building Air Conditioning System, Rev. 136
Tagout 0-TO-2003-0001, CREVS ‘A’ Bed Heater Stage 1 Implement DCN 63732
2-47E2865-4, Mechanical Ventilation & Air Conditioning Air Flow Diagram, Rev. 19
NEI 99-03, Control Room Habitability Assessment Guidance, June 2001
0-TI-560, Control Room Habitability Program, Rev. 0
SR 324767, Problem with 0-PDET-031-90 is affecting SR performance
SR 347986, Actual air flow calculated incorrectly
SR 348599, Control Bay Habitability Zone Breaches are not being closed in a timely manner
SR 369516, Measure the relief duct flow with the CREV A in service
PER 348012, Control Bay breach margin change
1-SR-3.4.5.2, Drywell Leak Detection Radiation Monitor Functional Test 1-RM-90-256, Rev. 8, performed June 2, 2011
FSAR Section 4.10, Nuclear System Leakage Rate Limits, BFN-22
FSAR Section 7.14, Drywell Leak Detection Radiation Monitoring System, BFN-17
Technical Specifications and Bases 3.4.5 RCS Leakage Detection Instrumentation, Amendment 263 and Rev. 43 respectively
1-TI-24, Primary Containment Leak Detection Continuous Air Monitor 1-RM-90-256 Alert and High Alarm Setpoint Determination, Rev. 2
1-SR-3.3.6.2.4(RX), Reactor Zone Isolation System Functional Test, Rev. 17
1-SI-4.2.A-16, Reactor Building Isolation Time Delay Relay Calibration, Rev. 22
Browns Ferry Nuclear Plant Technical Specifications, Section 3.3.6.2, Secondary Containment Isolation Instrumentation

Drawing 1-45E614-5, 120V AC/250V DC Valves and Misc. Schematic Diagram, Rev. 12
Drawing 1-45E777-3, 480V Unit Auxiliary Power Schematic Diagram, Rev. 23
3-SR-3.3.6.1.2(ATU B), Reactor Protection and Primary Containment Isolation Systems Analog Trip Unit Channel B1 Functional Test, Rev. 14
Browns Ferry Nuclear Plant Technical Specifications (Bases), Section 3.3.6.1, Primary Containment Isolation Instrumentation, Sept. 3, 1998
0-SR-3.8.1.6 – Common Accident Signal Logic, Rev. 20
SR 354036 - ‘A’ 4kV Auto/Lockout reset switch has bad coil
PER 354037 - ‘A’ 4kV Auto/Lockout reset switch has bad coil
WO: 111672614 – 0-SR-3.8.1.6 – Common Accident Signal Logic
2-SR-3.4.3.2, Main Steam Relief Valves Manual Cycle Test, Rev. 04

**Section 1EP6: Drill Evaluation**
EPIP-1, Emergency Classification Procedure, Rev. 47
EPIP-2, Notification of Unusual Event, Rev. 30
EPIP-3, Alert, Rev. 33
EPIP-8, Personnel Accountability and Evacuation, Rev. 23
CECC EPIP-1, Central Emergency Control Center (CECC) Operations, Rev. 52
CECC EPIP-2, Operations Duty Specialist Procedure for Notification of Unusual Event, Rev. 39
CECC EPIP-3, Operations Duty Specialist Procedure for Alert, Rev. 40
CECC EPIP-4, Operations Duty Specialist Procedure for Site Area Emergency, Rev. 41
NUREG-0654, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, Rev. 1
NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Rev. 6
Licensee’s time line for drill dated June 15, 2011
Performance Indicator Data for 2011 BFN Red Team Training Drill on June 15, 2011
Browns Ferry Training Drill controller notes dated June 15, 2011
WebEOC report dated June 15, 2011

**Section 4OA1: Performance Indicator Verification**
Browns Ferry Nuclear Plant Unit 1 MSPI Basis Documents, Revs. 5 and 6
Browns Ferry Nuclear Plant Unit 2 MSPI Basis Documents, Revs. 4 and 5
Browns Ferry Nuclear Plant Unit 3 MSPI Basis Documents, Revs. 4 and 5
Cause Determination Evaluation (CDE) 943, HPCI Isolation During Relay Testing (Boots)
CDE 944, HPCI Isolation During Functional Test (Meters)
CDE949, Unit 2 exceeded MR UA
CDE 989, HPCI Blew Out Temporary Tubing During Flow Rate Test
MSPI Derivation Reports for Units 1, 2, and 3, Various in 2010
NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Rev. 6
NPG-SPP-3.4, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting – 10CFR50.65, Rev. 0
SR 387798, Error in Unit 3 MSPI Basis Document
0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting – 10CFR50.65, Rev. 35
Unit 1, 2 and 3 Quarterly MSPI, HPI 2010/2011 PI Summary Sheet
Unit 1, 2 and 3 MSPI Derivation Reports for Unreliability and Unavailability Index for High Pressure Injection
Maintenance Rule Spreadsheets for Unreliability and Unavailability for HPCI

NPG-SPP-02.2, Performance Indicator Program, Rev. 2
Browns Ferry Nuclear Plant, Unit 1, MSPI Basis Document, Revs. 5, 6
Unit 1 MSPI Derivation Report, MSPI Heat Removal System, (UAI), Mar 2011, Dec., Sept., June 2010
Unit 1 MSPI Derivation Report, MSPI Heat Removal System, (URI), Mar 2011, Dec., Sept., June 2010
SR 393576, NRC Identified Missing Comment for Q1 2011 Unit 1 Heat Removal (RCIC) MSPI Submittal
Browns Ferry Nuclear Plant, Unit 2, MSPI Basis Document, Revs. 4, 5
Unit 2 MSPI Derivation Report, MSPI Heat Removal System, (UAI), Mar 2011, Dec., Sept., June 2010
Unit 2 MSPI Derivation Report, MSPI Heat Removal System, (URI), Mar 2011, Dec., Sept., June 2010
Browns Ferry Nuclear Plant, Unit 3, MSPI Basis Document, Revs. 4, 5
Unit 3 MSPI Derivation Report, MSPI Heat Removal System, (UAI), Mar 2011, Dec., Sept., June 2010
Unit 3 MSPI Derivation Report, MSPI Heat Removal System, (URI), Mar 2011, Dec., Sept., June 2010
LERs for 2010 and 2011
Maintenance Rule CDE Reports from April 1, 2010 - March 31, 2011

**Section 4OA2: Identification and Resolution of Problems**
Documents Reviewed:
NPG-SPP-02.7, PER Trending, Rev. 1
NPG-SPP-02.8, Integrated Trend Review, Rev. 1
Integrated Trend Report, Q1FY11, October 01, 2010 - December 31, 2010
Integrated Trend Report, Q2FY11, January 01, 2011 - March 31, 2011
PER 277476, PER 299892, PER 299888
PER 307617, PER 309223, PER 312297
PER 330400, PER 331889, PER 333344
PER 344473, PER 344533, PER 363748
PER 372584, PER 373365, PER 374948
PER 376872, PER 380306, PER 380900
PER 382350, PER 382971, PER 384686
PER 387154, PER 387156, PER 387161
PER 387163, PER 387166, PER 398609
PER 403622
SR 403233

## LIST OF ACRONYMS

| | | |
|---|---|---|
| ADAMS | - | Agencywide Document Access and Management System |
| ADS | - | Automatic Depressurization System |
| ARM | - | area radiation monitor |
| CAD | - | containment air dilution |
| CAP | - | corrective action program |
| CCW | - | condenser circulating water |
| CFR | - | Code of Federal Regulations |
| CoC | - | certificate of compliance |
| CRD | - | control rod drive |
| CS | - | core spray |
| DCN | - | design change notice |
| EECW | - | emergency equipment cooling water |
| EDG | - | emergency diesel generator |
| FE | - | functional evaluation |
| FPR | - | Fire Protection Report |
| FSAR | - | Final Safety Analysis Report |
| IMC | - | Inspection Manual Chapter |
| LER | - | licensee event report |
| NCV | - | non-cited violation |
| NRC | - | U.S. Nuclear Regulatory Commission |
| ODCM | - | Off-Site Dose Calculation Manual |
| PER | - | problem evaluation report |
| PCIV | - | primary containment isolation valve |
| PI | - | performance indicator |
| RCE | - | Root Cause Evaluation |
| RCW | - | Raw Cooling Water |
| RG | - | Regulatory Guide |
| RHR | - | residual heat removal |
| RHRSW | - | residual heat removal service water |
| RTP | - | rated thermal power |
| RPS | - | reactor protection system |
| RWP | - | radiation work permit |
| SDP | - | significance determination process |
| SBGT | - | standby gas treatment |
| SLC | - | standby liquid control |
| SNM | - | special nuclear material |
| SRV | - | safety relief valve |
| SSC | - | structure, system, or component |
| TI | - | Temporary Instruction |
| TIP | - | transverse in-core probe |
| TRM | - | Technical Requirements Manual |
| TS | - | Technical Specification(s) |
| UFSAR | - | Updated Final Safety Analysis Report |
| URI | - | unresolved item |
| WO | - | work order |