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

October 29, 2010

EA-10-215

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 05000259/2010004, 05000260/2010004, 05000296/2010004, 07200052/2010003, AND NOTICE OF VIOLATION

Dear Mr. Krich:

On September 30, 2010, 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 October 8, and October 22, 2010, 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.

Based on the results of this inspection, the NRC has determined that a Severity Level IV violation of NRC requirements occurred. The violation was evaluated in accordance with the NRC Enforcement Policy. The current Enforcement Policy is included on the NRC's Web site at (http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html). The violation is cited in the enclosed Notice of Violation (EA-10-215) and the circumstances surrounding it are described in detail in the subject inspection report. The violation is being cited in the Notice because it involved the repetitive failure to adequately control transient combustible materials (i.e-, diesel fuel) inside the Independent Spent Fuel Storage Installation (ISFSI) area and within close proximity of the dry casks loaded with spent fuel. This violation is being cited because the criterion specified in Section 2.3.2.a.3 of the NRC Enforcement Policy for a non-cited violation was not met. This criterion was not met because the violation was repetitive and identified by the NRC. The initial violation, also identified by the NRC, was documented in NRC Inspection Report 07200052/2010002.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. If you have additional information that you believe the NRC should consider, you may provide it in your response to the Notice. The NRC review of your response to the Notice will also determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

The NRC has also identified three additional findings that were evaluated under the risk significance determination process as having very low safety significance (Green). The NRC has also determined that violations are associated with these findings. These violations are being treated as Non-Cited Violations (NCVs), consistent with Section 2.3.2 of the Enforcement Policy. These NCVs are described in the subject inspection report. Additionally, three licensee-identified violations which were determined to be of very low safety significance are listed in this report. If you contest the violations or significance of these NCVs, 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 Resident Inspector at Browns Ferry Nuclear Plant

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, 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),accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html To the extent possible, your response should not include any personal privacy or proprietary, information so that it can be made available to the Public without redaction.

Sincerely,

/RA/

Eugene F. Guthrie, Chief
Reactor Projects Branch 6
Division of Reactor Projects

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

Enclosures:
1. Notice of Violation
2. NRC Integrated Inspection Report 05000259/2010004, 05000260/2010004, 05000296/2010004, and 07200052/2010003 w/attachment: Supplemental Information

cc w/encl. (See page 3)

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X PUBLICLY AVAILABLE ☐ NON-PUBLICLY AVAILABLE ☐ SENSITIVE X NON-SENSITIVE
ADAMS: ☐ Yes ACCESSION NUMBER:________________________ ☐ SUNSI REVIEW COMPLETE

OFFICE	RII:DRP	RII:DRP	RII:DRP	RII:DRP	RII:DRP	RII:DRP	RII:DRS
SIGNATURE	Via email	Via email	Via email	Via email	JDH /RA/	Via email	Via email
NAME	TRoss	CStancil	PNiebaum	LPressley	JHamman	WDeschaine	SWalker
DATE	10/28/2010	10/28/2010	10/29/2010	10/29/2010	10/29/2010	10/28/2010	10/28/2010
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO
OFFICE	RII:DRS	RII:DRS	RII:DRP	RII:DRS	RII:DRP	OE:EB	OE
SIGNATURE	Via email	Via email	EFG /RA for/	Via email	CRK /RA/	Via email	Via email
NAME	JEargle	CFletcher	MPribish	RWilliams	CKontz	JWray	LJarriel
DATE	10/28/2010	10/27/2010	10/29/2010	10/27/2010	10/29/2010	10/29/2010	10/29/2010
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO
OFFICE	RII:DRP						
SIGNATURE	EFG /RE/						
NAME	EGuthrie						
DATE	10/29/2010						
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

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Letter to R. M. Krich from Eugene Guthrie dated October 29, 2010

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2010004, 05000260/2010004, 05000296/2010004, 07200052/2010003, AND NOTICE OF VIOLATION

Distribution w/encl:
C. Evans, RII
L. Slack, RII
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RidsNrrPMBrownsFerry Resource

NOTICE OF VIOLATION

Tennessee Valley Authority	Docket No. 07200052
Browns Ferry Nuclear Plant	License No. 50-260
	EA-10-215

During an NRC inspection conducted on August 17, 2010, a violation of NRC requirements was identified. In accordance with the NRC Enforcement Policy, the violation is listed below:

> 10 CFR 72.212, Conditions of general license issued under §72.210, section (b)(9) stated, in part, that the licensee shall "Conduct activities related to storage of spent fuel under this general license only in accordance with written procedures." Procedure SPP-10.10, Control of Transient Combustibles, stated that requirements and controls for handling and use of transient combustibles associated with the BFN ISFSI/Dry Cask Storage Pad were contained within drawings 0-47E201-1 and 0-47E201-2. These drawings established limits for the amount of transient combustibles that could be stored in proximity to a loaded HI-STORM cask. In Table 1 of drawing 0-47E201-2, diesel fuel was specifically limited to 11.88 gallons within 40 feet of a loaded cask.
>
> Contrary to the above, a diesel-powered man-lift with 30 gallons of diesel fuel was discovered parked approximately 22 feet from a loaded HI-STORM cask on August 17, 2010. For approximately one month, this man-lift had been routinely parked in the same location well inside of the minimum allowed 40 feet from a loaded cask.

This is a Severity Level IV violation.

Pursuant to the provisions of 10 CFR 2.201, the Tennessee Valley Authority is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001 with a copy to the Regional Administrator, Region II, and a copy to the NRC Senior Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation; EA-10-215" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time. If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

In accordance with 10 CFR 19.11, you may be required to post this Notice within two working days of receipt.

Dated this 29 day of October 2010

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-259, 50-260, 50-296, and 72-052
License Nos.:	DPR-33, DPR-52, DPR-68
Report No.:	05000259/2010004, 05000260/2010004, 05000296/2010004, AND 07200052/2010003
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Units 1, 2, and 3
Location:	Corner of Shaw and Nuclear Plant Roads Athens, AL 35611
Dates:	July 1, 2010 through September 30, 2010
Inspectors:	T. Ross, Senior Resident Inspector C. Stancil, Resident Inspector P. Niebaum, Resident Inspector L. Pressley, Resident Inspector J. Hamman, Project Engineer (1RO4.2, 1RO18.2, 1RO19, 4OA5.6) W. Deschaine, Project Engineer (1RO6.2, 1RO18.1, 1RO19) S. Walker, Senior Reactor Inspector (4OA5.5) J. Eargle, Reactor Inspector (4OA5.5) C. Fletcher, Senior Reactor Inspector (4OA5.5) M. Pribish, Resident Inspector (4OA5.5) R. Williams, Reactor Inspector (4OA5.5) C. Kontz, Senior Project Engineer (4OA5.6) J. Wray, Senior Enforcement Specialist (4OA5.6) L. Jarriel, Agency Allegation Advisor (4OA5.6)
Approved by:	Eugene F. Guthrie, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure 2

SUMMARY OF FINDINGS

IR 05000259/2010004, 05000260/2010004, 05000296/2010004, and 07200052/2010003; 07/01/2010 – 09/30/2010; Browns Ferry Nuclear Plant, Units 1, 2 and 3; Maintenance Risk Assessments, and Other Activities.

The report covered a three month period of inspection by the resident inspectors, reactor inspectors from Region II, Headquarters personnel, and an announced inspection of five regional inspectors for the inspection of Temporary Instruction (TI)-177. One cited violation (VIO), and three 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). 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. NRC Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," for failure to establish a preventive maintenance (PM) test program for safety-related molded case circuit breakers (MCCBs) to demonstrate these breakers would perform satisfactorily upon demand. Since initial startup of all three units, the inspectors found that the licensee had not included 612 critical MCCBs, many of them safety-related, in their PM program which resulted in the MCCBs receiving no planned maintenance or testing. The licensee entered this issue into the corrective action program as problem evaluation report (PER) 209095. The licensee's corrective actions included: identifying all critical MCCBs that required preventive maintenance, developing test procedures for these MCCBs, performing testing for all affected MCCBs, and conducting an extent-of-condition review of all safety-related components potentially excluded from the PM program.

  This finding was determined to be of greater than minor significance because it was associated with the Protection Against External Factors attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events, such as fire, that challenge critical safety functions during shutdown as well as power operations. Specifically, the lack of a PM program for safety-related MCCBs resulted in no periodic planned maintenance or testing being performed since original installation, which in most cases was over thirty years. Based on operating experience, this could result in a breaker being slow to trip or sticking in the "on" position after an over-current condition. In accordance with IMC 0609, Significance Determination Process (SDP), Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings," this finding was determined to require a Phase 3 analysis since the finding represented an increase in the likelihood of a fire caused by an electrical fault at the MCCB compartment with the breaker not opening. A regional Senior Reactor Analyst conducted a Phase 3 SDP analysis, which concluded that the finding was of very low safety significance (Green).

The cause of this finding was directly related to the cross cutting aspect of Appropriate Corrective Actions in the Corrective Action Program component of the Problem Identification and Resolution area, because the licensee did not adequately implement corrective actions to resolve the deficiencies previously identified by PER 131875 regarding certain Westinghouse MCCBs that were not in the PM program [P.1(d)]. (Section 4OA5.4)

Cornerstone: Mitigating Systems

- Green. An NRC-identified Green non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified for the licensee's failure to perform functional evaluations in accordance with procedure NEDP-22, Functional Evaluations, when gas was identified in the High Pressure Coolant Injection (HPCI) System during the Technical Specification required surveillance. The licensee has subsequently performed functional evaluations of the occurrences and entered the issue into their corrective action program as problem evaluation report (PER) 223067.

  This finding was considered more than minor because it adversely affected the Mitigating Systems Cornerstone objective of ensuring the availability and reliability of safety systems, and is related to the attribute of Procedure Quality (i.e.- Maintenance and Testing Procedures). Specifically, the failure to perform a functional evaluation or provide adequate justification for not performing one upon identification of gas during venting of the system could affect the operability, availability, and reliability of the HPCI system or could result in missing an opportunity to identify the source of voiding to preclude future inoperability. This deficiency also paralleled Inspection Manual Chapter 0612, Appendix E, Example 4.a, as the licensee routinely did not perform the required functional evaluations. The team assessed this finding using Inspection Manual Chapter 0609, Significance Determination Process, and determined that the finding was of very low safety significance (Green) because subsequent functional evaluations showed that the gas voids did not impact the operability of the HPCI system.

  The cause of this finding was directly related to the cross cutting aspect of Evaluation of Identified Problems in the Corrective Action Program component of the Problem Identification and Resolution area, in that the licensee failed to thoroughly evaluate gas voids such that the resolution addressed causes and extent of conditions, as necessary, and included the failure to thoroughly evaluate for operability and reportability conditions adverse to quality. [P.1(c)] (Section 4OA5)

- Green. The inspectors identified a non-cited violation of 10 CFR Part 50.65 (a)(4), for inadequate risk assessments of on-line risk associated with ongoing maintenance activities. Specifically, on July 21 and then again on September 16, 2010, the inspectors found that the licensee failed to perform a probabilistic risk analysis (PRA) evaluation of the multiple risk significant equipment that had been taken out of service for planned on-line maintenance. The licensee entered this issue into the corrective action program as problem evaluation reports (PERs) 241885 and 254000. In both instances the licensee subsequently performed the required PRA evaluations which determined the on-line risk to be Green.

This finding affected the Mitigating Systems cornerstone and was determined to be greater than minor according to Inspection Manual Chapter (IMC) 0612, Appendix B, Issue Screening, because minor violations of 10 CFR 50.65(a)(4) have occurred repeatedly on five occasions and if continued to be left uncorrected would have the potential to lead to a more significant safety concern. The significance of this finding was evaluated using IMC 0609, Appendix K, Maintenance Risk Assessment and Risk Management Significance Determination Process. Based on Appendix K, the inspectors determined that this finding was of very low safety significance (Green) because the licensee's PRA evaluation concluded the actual risk deficit was less than 1E-6 for the incremental core damage probability deficit (ICDPD) and less than 1E-7 for the incremental large early release probability deficit (ILERPD). The cause of this finding was directly related to the cross cutting aspect of Procedural Compliance in the Work Practices component of the Human Performance area, because the licensee failed to follow the instructions in 0-TI-367 which required a PRA evaluation to be performed in accordance with SPP-9.1 [H.4(b)]. (Section 1R13)

B. Licensee Identified Violations

Three violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and the corrective action program tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at essentially full Rated Thermal Power (RTP) the entire report period except for two planned downpowers, and several weeks of reduced power due to elevated river water temperatures. On July 10, 2010, a planned downpower to 75 percent RTP was conducted to clean main condenser waterboxes. Unit 1 was returned to 94 percent RTP on July 11, but power ascension was limited by elevated river temperatures. Between July 12 and July 16, 2010, several unplanned downpowers, some as low as 54 percent RTP, were conducted due to elevated river water temperatures. The unit returned to full RTP on July 16, 2010. Between July 23 and August 29, 2010, additional unplanned downpowers as low as 50 percent RTP were conducted due to elevated river water temperatures. For the majority of the time between July 23 and August 29, Unit 1 power was maintained at 50 percent RTP. The unit returned to full RTP on August 29, 2010. On August 31, 2010, a planned downpower to 70 percent RTP was conducted for a control rod pattern adjustment and the unit returned to full RTP the same day.

Unit 2 operated at essentially full RTP the entire report period except for one planned downpower, and several weeks of reduced power due to elevated river water temperatures. On July 2, 2010, a planned downpower to 90 percent RTP was conducted to isolate a main condenser waterbox leak; Unit 2 was returned to 99 percent RTP that same day, limited by main condenser vacuum. The main condenser leak was repaired and the unit returned to full RTP on July 8, 2010. Between July 15 and July 18, 2010, several unplanned downpowers, some as low as 56 percent RTP, were conducted due to elevated river water temperatures. Unit 2 returned to full RTP on July 18, 2010. Between July 22 and August 30, 2010, additional unplanned downpowers as low as 50 percent RTP were conducted due to elevated river water temperatures. For the majority of the time between July 22 and August 30, unit power was maintained at 50 percent RTP. The unit returned to full RTP on August 30, 2010.

Unit 3 operated at essentially full RTP the entire report period except for one planned downpower, one unplanned downpower, several weeks of reduced power and one unplanned shutdown. On July 15, 2010, an unplanned downpower to 54 percent RTP was conducted due to elevated river water temperatures, Unit 3 was returned to full RTP the next day. Between July 23 and August 30, 2010, additional unplanned downpowers as low as 40 percent RTP were conducted due to elevated river water temperatures. For the majority of the time between July 23 and August 30, Unit 3 power was maintained at 50 percent RTP. However, on August 12, 2010, an unplanned shutdown from 50 percent RTP was conducted to identify and repair a significant packing leak on a reactor head vent valve. The unit performed a reactor startup (Mode 2) on August 13, and returned to 40 percent RTP on August 17 limited by elevated river temperatures. Also, between August 25 and 28, Unit 3 power was limited to 68 percent RTP for power suppression testing of a fuel rod leak. The unit returned to full RTP on August 30, 2010. On September 10, 2010, a planned downpower to 65 percent RTP was conducted to perform a control rod sequence exchange, scram time testing, and power suppression of a fuel rod leak. Unit 3 returned to full RTP on September 14, 2010.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

The inspectors conducted four 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. Documents reviewed are listed in the Attachment to this report.

- Emergency Equipment Cooling Water (EECW) System
- Unit 1 Reactor Core Isolation Cooling (RCIC) System
- Unit 3 Residual Heat Removal (RHR) System - Division II
- Unit 3 High Pressure Coolant Injection (HPCI) System

b. Findings

No findings were identified.

.2 Complete Walkdown

a. Inspection Scope

The inspectors conducted a complete walkdown inspection of the Unit 3 Core Spray (CS) system, using the applicable P&ID flow diagram (3-47E814-1), and the relevant operating instruction (OI), 3-OI-75, Core Spray System, to verify equipment alignment, availability and operability. The inspectors also reviewed relevant portions of the UFSAR and TS. This detailed equipment alignment walkdown verified valve positions, electrical power lineup, configuration of applicable system instrumentation and controls, component labeling, pipe hangers and support installation, and associated support systems status. Furthermore, the inspectors examined the applicable System Health Report, outstanding Work Orders (WO), and open Problem Evaluation Reports (PERs) that could affect system alignment and operability. This activity constituted one inspection sample.

b. Findings

No findings were identified.

1R05 Fire Protection

.1 Fire Protection Tours

a. Inspection Scope

The inspectors reviewed licensee procedures, Standard Programs and Processes (SPP)-10.10, Control of Transient Combustibles, and SPP-10.9, Control of Fire Protection Impairments, and conducted a walkdown of the four 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 SPP-10.9. Furthermore, the inspectors reviewed applicable portions of the Site Fire Hazards Analysis Volumes 1 and 2 and Pre-Fire Plan drawings to verify that the necessary firefighting equipment, such as fire extinguishers, hose stations, ladders, and communications equipment, was in place.

- Unit 3 Reactor Building, elevation 519' through 565' (FZ 3-1)
- Unit 3 Battery and Battery Board Rooms, Control Building elevation 593' (FA-19)
- Units 1 and 2 Emergency Diesel Generator (EDG) Building (FA - 20)
- Unit 3 EDG Building (FA - 21)

b. Findings

No findings were identified.

1R06 Internal Flood Protection Measures

.1 Review of Areas Susceptible to Internal Flooding

a. Inspection Scope

The inspectors reviewed applicable sections of licensing basis documents such as the UFSAR; Design Criteria BFN 50-C-075, Pipe Rupture, Internal Missiles, Internal Flooding, Seismic Qualification, and Vibration Qualification of Piping; NUREG-1232, Volume 3, Supplement 1, Safety Evaluation Report for BFN Unit 2 Restart, Section 3.8, Moderate-Energy Line Breaks; Design Basis Evaluation Report MELB Flood Evaluation Requirements For BFN Unit 2 Restart; Moderate Energy Line Break Flood Evaluation Report for Unit 1-Extended Power Uprate; and the Browns Ferry Nuclear Plant Probabilistic Safety Assessment Initiating Event Notebook, Initiating Event Frequencies.

The inspectors performed a walkdown of the internal flood protection features of one risk-significant area. These areas were the Unit 1 and 2 EDG building, and the Unit 3 EDG building, which included EECW system supply and discharge piping, sumps, and drain piping for internal flood protection measures. The inspectors specifically examined plant design features and measures intended to protect the plant and susceptible safety-related systems and equipment from an internal flooding event in the EDG Buildings, such as drains, sump level switches, room sumps and sump pumps, door seals, conduit seals and instrument racks that might be subjected to flood conditions.

The inspectors reviewed selected, completed preventive maintenance (PM) procedures, WOs, and surveillance procedures to verify that actions were completed within the specified frequency and in accordance with program requirements. The inspectors also reviewed applicable emergency operating instructions (EOIs), and annunciator response procedures (ARPs) for mitigating and responding to flooding events to verify that licensee actions were consistent with the plant's licensing and design basis. Furthermore, the inspectors reviewed the PERs initiated for the previous 12 months with respect to flood-related items to verify that problems were being identified and entered into the corrective action program.

b. Findings

Introduction: The inspectors identified an unresolved item (URI) regarding a variety of materials left unattended, unanchored and improperly stored in the lower corridors of both of the Unit 1/2 and Unit 3 EDG buildings that could have adversely impacted the capability of the emergency drainage systems credited in the licensee's internal flooding analysis for these buildings.

Description: During an internal flood protection walk-down of the Unit 1 and 2 EDG building, and the Unit 3 EDG building, the inspectors identified unattended and loose materials in the lower corridors that contain the EECW North and South supply header piping. The inspectors observed a 24-inch emergency drain in the Unit 1/2 EDG building lower corridor located in the Southwest corner. This drain emptied into the yard area just west of the Unit 1/2 EDG building and was shown on drawing 0-47E851-1, Rev. 29. In addition, the inspectors observed two 18-inch drains in the Unit 3 DG building lower corridor floor. These drains emptied into the yard area just east of the Unit 3 DG building and were shown on drawing 0-47E851-4, Rev. 13. The uncontrolled materials identified by the inspectors were of sufficient type and quantity to potentially obstruct the lower corridor emergency drains that were designed to mitigate the consequences of an internal flood due to the rupture of an EECW header. Furthermore, none of the doors that provide access to the four EDG rooms from the lower corridor were designed to be watertight.

The inspectors reviewed the licensee's Probabilistic Risk Analysis (PRA) for Internal Flooding as described in calculation number NDN-000-999-2007-0031, Rev 0. This analysis stated "Flooding in the diesel-generator buildings could result from failure of the EECW headers that pass through the buildings. The diesel-generator buildings, however, are provided with a 24-inch emergency drain in the wall that empties into a culvert in the yard." It further states "The common [i.e.- Unit 1/2] diesel generator building corridor has sump pumps and 24-inch drains. These are adequate to mitigate floods and major floods in the common corridors, so only one DG can be impacted by a flood." In the summary of qualitative screening results, the licensee concluded that a flood in the DG building lower corridor would result in "no submergence due to large drains and no impacted SSC's."

The inspectors also reviewed the licensee's detailed design criteria document for the diesel generators, BFN-50-7082, Rev. 15. Section 3.7.4 stated that the EDG units shall be located in separate rooms to ensure that flooding, resulting from a postulated failure in the pressure boundary of any water systems, would not prevent the standby DG system from performing its safe shutdown function.

The licensee initiated PER 256390 to evaluate the impact of the loose materials on the function of the EDG building lower corridor emergency drains. Additionally, the licensee removed the materials from the EDG buildings and added a daily requirement for the auxiliary unit operators (AUOs) to verify no unattended loose material in the EDG buildings lower corridors.

Summary: This issue is unresolved pending further inspection to determine more specifically the adverse impact of the improperly stored materials in the EDG building lower corridors upon the drainage system, the availability and capability of other internal flooding mitigation features (e.g., sump level alarms), and the current licensing basis for moderate energy line breaks (MELB) in the EDG buildings. The URI for this issue is identified as 05000259, 260, and 296/2010004-01, Uncontrolled Materials Adversely Impacted the Capability of the EDG Building Emergency Drainage System to Mitigate an Internal Flooding Event.

.2 Annual Review of Cables Located in Underground Bunkers/Manholes

a. Inspection Scope

The inspectors conducted an inspection of underground bunkers/manholes subject to flooding that contain cables whose failure could disable risk-significant equipment. The inspectors performed walkdowns of risk-significant areas, including Hand-Hole (HH) 15 and HH-26 located in the yard area east of the reactor building as well as the cable tunnel connecting the Unit 3 turbine building with the Intake Building, to verify that cables were not submerged in water, cables and/or splices appeared intact, and to observe the condition of cable support structures. When applicable, the inspectors verified proper dewatering device (sump pump) operation and verified level alarm circuits were set appropriately to ensure that affected cables would not become submerged. Where dewatering devices were not installed, the inspectors ensured that drainage was provided and was functioning properly. This activity constituted one inspection sample.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification

.1 Resident Inspector Quarterly Review

a. Inspection Scope

On August 9, 2010, the inspectors observed an as-found licensed operator requalification simulator examination for an operating crew according to Unit 3 Simulator Evaluation Guide OPL178.063, Loss of DG 3D, Loss of Off-Site Power, HPCI Failure, LOCA, Diesel and Core Spray Failures.

The inspectors specifically evaluated the following attributes related to each 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 US and Shift Manager (SM)

The inspectors attended a 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 constituted one inspection sample.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness

.1 Routine

a. Inspection Scope

The inspectors examined one specific equipment issue 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 (a)(1) goals and corrective actions (i.e.- Ten Point Plan). The inspectors also compared the licensee's performance against site procedure SPP-6.6, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting; Technical Instruction 0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting; and SPP 3.1, Corrective Action Program. The inspectors also reviewed, 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.

- Excess Flow Check Valves Exceeded Reliability Performance Criteria

b. Findings

No findings were identified.

.2 Periodic Evaluation Required by 10CFR 50.65(a)(3)

a. Inspection Scope

The inspectors reviewed the licensee's periodic evaluation of its Maintenance Rule (MR) Program required by 10 CFR 50.65(a)(3) with regard to some or all of the following attributes: (1) Timeliness of the evaluation; (2) Scope of the evaluation included review of (a)(1) goals, (a)(2) performance criteria, monitoring, PM activities, and effectiveness of corrective actions; (3) Industry operating experience was taken into account; and (4) Appropriate adjustments to the MR program were made as warranted. The inspectors also reviewed the licensee's evaluation to assess whether the balance between reliability and availability of SSCs was reviewed, and changes to the PM program were made if appropriate. The inspectors interviewed licensee personnel, reviewed applicable PERs, and attended MR expert panel meetings to verify that the evaluation results were appropriately considered.

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 six 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 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.

- On July 21, Unit 1 HPCI, C3 EECW, and A & G Control Air Compressors (CAC) were Out of Service (OOS) for maintenance
- On July 27, Unit 3 RCIC System, A and G CACs were OOS for maintenance
- On July 28, Unit 1 HPCI, 1C Reactor Feed Pump, Main Bank Battery 3, and A & G CACs were OOS for maintenance
- On August 5, Unit 1 RHR Loop I, G CAC, and Main Bank Battery 3 were OOS for maintenance with emergent work on A EDG
- On August 31, 1A Control Rod Drive (CRD) Pump, A EDG, Unit 1 RCIC and 1A Control Room Emergency Ventilation (CREV) System were OOS for maintenance
- On September 16, Unit 2 HPCI, D EDG, and G CAC were OOS for maintenance

b. Findings

Introduction: A non-cited violation (NCV) of 10 CFR Part 50.65 (a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," was identified by the NRC for the licensee's inadequate assessment of on-line risk associated with ongoing maintenance activities. Specifically, on July 21 and then again on September 16, 2010, the licensee failed to perform a probabilistic risk analysis PRA evaluation of the multiple risk significant equipment OOS for planned maintenance.

Description: On July 21, 2010, during the licensee's conduct of regularly scheduled work week (WW) 1029 maintenance activities, the inspectors reviewed the scope of ongoing maintenance associated with risk significant SSCs for Unit 1. At the time of the inspection, the C3 EECW pump, Unit 1 HPCI system, and plant CACs A and G were all OOS for planned maintenance. However, the inspectors identified that the licensee had not performed a PRA evaluation for this specific combination of OOS risk significant SSCs. In fact, no PRA evaluation of the WW had been performed at all. Section 3.2, Assessing Risk, of NPG-SPP-07.1, On Line Work Management, required a risk assessment methodology to be used for on-line maintenance prior to implementation of the maintenance. In addition, Section 3.2 states risk assessment guidelines utilize the results of the site PRA as described by site-specific Technical Instructions (TI). To evaluate the increased risks associated with on-line maintenance activities the licensee routinely utilized 0-TI-367, BFN Equipment to Plant Risk Matrix. But according to 0-TI-367, Illustration 2, Additional Risk Significant Components for Consideration, if more than one component is removed from a single system (e.g., two CACs) in addition with a single component (e.g., HPCI) from Illustration 1, BFN Equipment to Plant Risk Matrix, then a PRA evaluation was required to adequately assess the risk per SPP-9.11, Probabilistic Risk Assessment Program. Upon notification by the inspectors, the licensee initiated PER 240789 and promptly performed a PRA evaluation. The inspectors subsequently reviewed PRA Evaluation Response # BFN-0-10-075, for the aforementioned OOS risk significant SSCs, which determined the on-line risk was Green. Furthermore, the inspectors reviewed the corrective action plan for PER 240789 which primarily involved a briefing of all WW Managers on this event and the requirements of 0-TI-367 by the next day.

On September 16, 2010, during the licensee's conduct of regularly scheduled WW 1037 maintenance activities, the inspectors reviewed the scope of ongoing maintenance associated with risk significant SSCs for Unit 2. At the time of the inspection, the Unit 2 HPCI system, D EDG, and plant CAC G were all OOS for planned maintenance. However, the inspectors identified that the licensee had not performed a PRA evaluation for this specific combination of OOS risk significant SSCs. In fact, no PRA evaluation of this specific WW had been performed at all even though it was required by 0-TI-367. Illustration 2 of 0-TI-367 specifically stated that if two components from Illustration 1 (e.g., EDG and HPCI) and another component from Illustration 2 (e.g., CAC) were OOS concurrently then a PRA evaluation was required. After being notified by the NRC, the licensee initiated PER 2454000 and promptly performed a PRA evaluation. The inspectors subsequently reviewed PRA Evaluation Response # BFN-0-10-102, for the aforementioned OOS risk significant SSCs, which determined the on-line risk was Green. Furthermore, the inspectors reviewed the corrective action plan for PER 254000 which was still in progress.

In addition to the two instances mentioned above, the inspectors identified three other instances (two during the second quarter of 2010, and one in 2009) that involved inadequate risk assessments by the licensee for failing to recognize a PRA evaluation was required by 0-TI-367. These instances were entered into the licensee's CAP as PER 165699, 230291, and 232173.

<u>Analysis</u>: The inspectors determined that the licensee's failure to conduct an adequate risk assessment on July 21 and September 16, 2010, of the multiple risk significant SSCs that were OOS for planned maintenance constituted a performance deficiency. This finding affected the Mitigating Systems cornerstone and was determined to be greater than minor according to Inspection Manual Chapter (IMC) 0612, Appendix B, Issue Screening and section 2.10.F of the Enforcement Manual, because minor violations of 10 CFR 50.65(a)(4) have occurred repeatedly on five occasions and if continued to be left uncorrected would have the potential to lead to a more significant safety concern. The significance of this finding was evaluated using IMC 0609, Appendix K, Maintenance Risk Assessment and Risk Management Significance Determination Process. Based on Appendix K, the inspectors determined that this finding was of very low safety significance (Green) because the licensee's PRA evaluation concluded the actual risk deficit was less than 1E-6 for the incremental core damage probability deficit (ICDPD) and less than 1E-7 for the incremental large early release probability deficit (ILERPD). The cause of this finding was directly related to the cross cutting aspect of Procedural Compliance in the Work Practices component of the Human Performance area, because the licensee failed to follow the instructions in 0-TI-367 which required a PRA evaluation to be performed in accordance with SPP-9.1 (H.4.b).

Enforcement: 10 CFR 50.65(a)(4) required, in part, that prior to performing maintenance activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to this, on July 21 and September 16, 2010, the licensee failed to adequately assess the risk associated with on-line maintenance activities of risk significant SSCs on Unit 1 and Unit 2, respectively. However, because the finding was determined to be of very low safety significance and has been entered into the licensee's CAP as PERs 240789, 241885 and 254000, this violation is being treated as an NCV consistent with Section 2.3.2 of the Enforcement Policy. This NCV is identified as NCV 05000259, and 260/2010004-02, Failure to Adequately Assess Online Risk Associated with Maintenance Activities on Risk Significant SSCs.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the eight 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 Common: C Residual Heat Removal Service Water (RHRSW) Pump Room Watertight Door Seal Gap (PERs 227113 and 223439)
- Unit Common: A, B, and D RHRSW Pump Room Watertight Door Degradations (PERs 240518 and 133899)
- HPCI Turbine Stop Valve Mechanical Trip Hold Valve (1/2/3-PCV-073-0018C) Diaphragm Defect Per 10 CFR 21 Notification (PER 238036)
- Unit Common: RHRSW Pump Room Sump Pump Inadequate Flow Capacities (PER 223614)
- Unit 3 161 KV Offsite Power Supply With 161KV Capacitor Bank No. 2 OOS
- Unit 1 RHR Division I and Unit 2 RHR Division II Room Cooler Reduced Flow (PER 238010)
- Unit 2 RHR Division II Drywell Spray Piping Void (PER 235900)
- ECCS Piping Air Entrainment (PERs 226630 and 226628)

b. Findings

No findings were identified.

1R18 Plant Modifications

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the temporary modification listed below and licensee procedure NPG-SPP-9.5, Temporary Alterations, to verify regulatory requirements were met. 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 the 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.

- TACF 0-10-004-067/R0, Differential Pressure Gauges across the Unit 1 and 2 EDG Heat Exchanger EECW Supply

b. Findings

No findings were identified.

.2 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed Design Change Notice (DCN) 69932, Revise Controller Setpoints [HPCI and RCIC Flow] to Resolve PER 221522, and the associated completed work package, including related documents and procedures. The inspectors reviewed licensee procedure NPG-SPP-9.3, Plant Modifications and Engineering Change Control, and observed part of the licensee's activities to implement this design change made while the unit was online. The inspectors reviewed the associated 10 CFR 50.59 screening against the system design bases documentation to verify that the modifications had not affected system operability/availability. The inspectors reviewed selected ongoing and completed work activities to verify that installation was consistent with the design control documents.

b. Findings

No findings were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the six 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(s) that may have been affected were adequately tested, that the acceptance criteria were consistent with information in the applicable licensing basis and/or design basis documents, and that the procedure had been properly reviewed and approved. The inspectors also witnessed the test and/or reviewed the test data, to verify that test results adequately demonstrated restoration of the affected safety function(s). The inspectors 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 1: PMT for 1B Core Spray Room Cooler Coil Replacement per WO 09-713772722790-000
- Unit 2: PMT for APRM-2 Relay Failed to De-energize per WO 111307032
- Unit 3: PMT for 2A Recirculation Loop Flow Indication to APRM-2 Troubleshoot/Repair per WO 111279809
- Unit 1: PMT for HPCI Turbine Stop Valve Mechanical Trip Hold Valve (1-PCV-73-0018C) Diaphragm Replacement per WO 111148386 and Section 7.3, HPCI Pre-Startup Checks, of 1-SR-3.5.1.7, HPCI Main and Booster Set Developed Head and Flow Rate Test
- Unit 1/2: PMT for D EDG Battery Replacement per WO 10552427 and 111344510, 0-SR-3.8.4.2 (DG-D), and 0-SR-3.8.6.2 (DG-D)
- Unit 2: PMT for HPCI Turbine Stop Valve Mechanical Trip Hold Valve (2-PCV-073-0018C) Diaphragm Replacement per WO 111148387 and 2-SR-3.5.1.7, HPCI Main and Booster Pump Set Developed Head and Flow Rate Test

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities

.1 Unit 3 Forced Shutdown Due To Unidentified Reactor Coolant Leak

a. Inspection Scope

On August 12, 2010, Unit 3 commenced an unplanned forced shutdown due to a sudden increase in the unidentified reactor coolant system (RCS) leakage. The RCS unidentified leakrate had increased to approximately 1.75 gpm, and was subsequently determined to be a packing leak from a reactor vessel head vent isolation valve (3-VTV-1-502) in the drywell. The leak was repaired and operators commenced restart of Unit 3 (i.e.-entered Mode 2) on August 13. Unit 3 was tied to the grid on August 14. During this short notice forced outage 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. The more significant outage activities witnessed, monitored, examined and/or reviewed by the inspectors were as follows:

- Shutdown and cooldown of Unit 3 in accordance with general operating instruction (GOI) 3-GOI-100-12A, Unit Shutdown from Power Operations to Cold Shutdown and Reduction in Power During Power Operations, and 3-SR-3.4.9.1(1), Reactor Heatup and Cooldown Rate Monitoring
- Control of Hot Shutdown (Mode 3) conditions, and critical plant parameters
- Reactor coolant system and heatup/pressurization to rated temperature and pressure per 3-SR-3.4.9.1(1), Reactor Heatup and Cooldown Rate Monitoring
- Plant Oversight Review Committee (PORC) restart meetings on August 13, 2010
- Reviewed licensee execution of 3-GOI-200-2, Drywell Closeout; and conducted an independent closeout inspection of the Unit 3 Drywell on August 13
- Reactor startup and power ascension activities in accordance with 3-GOI-100-1A, Unit Startup
- 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 Unit 3 forced outage and verified that initiation thresholds, priorities, mode holds, and significance levels were assigned as required.

b. Findings

No findings were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed portions and/or reviewed completed test data for the following five 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:

- 1-SR-3.5.3.3, RCIC System Rated Flow at Normal Operating Pressure
- 3-SR-3.5.3.3(COMP), RCIC Comprehensive Pump Test
- 3-SR-3.5.1.6(RHR II), Quarterly RHR System Rated Flow Test Loop II

Routine Surveillance Tests:

- 2-SR-3.3.1.1.16(APRM-2), Average Power Range Monitor Functional Test - APRM 2
- 2-SR-3.7.5.1, Turbine Bypass Valve Cycling

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

During the report period, the inspectors observed a Radiological Emergency Preparedness (REP) drill that contributed to the licensee's Drill/Exercise Performance (DEP) and Emergency Response Organization (ERO) performance indicator (PI) measures on August 18, 2010, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation (PAR) development activities. The inspectors observed ERO operations in the simulated control room and Technical Support Center 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's critique of the REP drill to verify any inspector observed weaknesses were also identified by the licensee.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

.1 Cornerstone: Mitigating Systems

Mitigating Systems Performance Indicator

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the Performance Indicators (PIs) listed below, including procedure NPG-SPP-2.2, Performance Indicator Program. The inspectors examined the licensee's PI data for the specific PIs listed below for the third quarter of 2009 through the second quarter of 2010. The inspectors independently screened maintenance rule cause determination and evaluation reports and calculated selected reported values to verify their accuracy. The inspectors also compared the licensee's raw data against graphical representations and specific values reported to the NRC for the second quarter 2010 PI report to verify that the data was correctly reflected in the report. Additionally, the inspectors 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 Mitigating Systems Performance Index - Emergency AC Power
- Unit 2 Mitigating Systems Performance Index - Emergency AC Power
- Unit 3 Mitigating Systems Performance Index - Emergency AC Power
- Unit 1 Mitigating Systems Performance Index - Residual Heat Removal
- Unit 2 Mitigating Systems Performance Index - Residual Heat Removal
- Unit 3 Mitigating Systems Performance Index - Residual Heat Removal
- Unit 1 Mitigating Systems Performance Index - Cooling Water (RHRSW/EECW)
- Unit 2 Mitigating Systems Performance Index - Cooling Water (RHRSW/EECW)
- Unit 3 Mitigating Systems Performance Index - Cooling Water (RHRSW/EECW)

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 CAP. This review was accomplished by reviewing daily PER report summaries, periodically attending Corrective Action Review Board (CARB) meetings and periodically attending PER Screening Committee (PSC) meetings.

.2 Focused Annual Sample Review - Operator Workarounds

a. Inspection Scope

The inspectors conducted a review of existing Operator Workarounds (OWA) to verify that the licensee was identifying OWAs at an appropriate threshold, entering them into the corrective action program, establishing adequate compensatory measures, prioritizing resolution of the problem, and implementing appropriate corrective actions in a timely manner commensurate with its safety significance. The inspectors examined all active OWAs listed in the Limiting Condition of Operation Tracking (LCOTR) Log, and reviewed them against the guidance in OPDP-1, Conduct of Operations, Section 4.7.B, Operator Workarounds (OWAs) and BFN-ODM-4.16, Operator Workarounds, Burdens and Challenges. The inspectors also discussed these OWAs in detail with on shift operators to assess their familiarity with the degraded conditions and knowledge of required compensatory actions. Furthermore, the inspectors walked down selected OWAs, and verified the ongoing performance, and/or feasibility of, the required actions. Lastly, for selected OWAs, the inspectors reviewed the applicable PER, including the associated functional evaluation and corrective action plans (both interim and long term).

b. Findings and Observations

No findings were identified. However, the inspectors had the following observations which were discussed with the licensee:

Inspectors noted that the quarterly aggregate OWA assessments performed by Operations missed some opportunities to enhance organizational effectiveness in managing the use of OWAs:

- Compensatory action for 0-023-OWA-2010-0041 to align RHR heat exchangers during a design basis accident was improperly classified as a Challenge instead of a higher level Workaround which is more appropriate for emergency or abnormal operations. The licensee reclassified the OWA as a Workaround and initiated PER 256400.

- The LCOTR report was often not complete which required the implementing watch stander to read the detailed OWA description each time to acquire a full understanding of the OWA. PER 257374 was initiated to develop a better watch station tracking tool.

- Lack of detailed weekly OWA reviews by the shift technical advisor for which the licensee initiated PER 252936.

- A consolidated (aggregate) impact on each watch station from all Workarounds, Burdens, and Challenges was not consistently or effectively performed. The licensee did not thoroughly assess the aggregate impact of the collective (total combined) impacts from all OWAs on each watch station. The licensee's procedural guidance assigned an aggregate threshold of one hour per watch station shift as a limit to evaluate the impact in the CAP, but the quarterly aggregate assessment only evaluated impacts from a specific category of OWAs (i.e. – Workarounds, Challenges, or Burdens). For instance, the most recent assessment indicated the impact from Challenges on the Unit 1 Unit Operator (UO) watch station was only 45 minutes per shift. However, if the collective impact was assessed from all OWAs, the total impact on the Unit 1 Unit Operator would be over 100 minutes per shift. In addition, separation of routine and conditional impacts is non-conservative in that there is no guarantee that they won't happen at the same time. Also, the nature of routine impacts is that they detract from normal board observation which could contribute to the operators not being aware of developing events that will require conditional responses. The licensee referenced PER 240967, previously identified in a self-assessment with corrective action pending, which will evaluate and revise the aggregate assessment program.

- The aggregate impact did not include the time to administratively manage OWAs, especially pertinent for watch stations with large OWA burdens such as the Units 1 and 3 UOs (100 and 80 minutes respectively). Inspectors noted that UOs would spend as much as 20-30 additional minutes working through an updated LCO Tracking report just to identify all the OWAs that needed to be done.

4OA3 Event Follow-up

.1 (Closed) Licensee Event Report (LER) 05000296/2010-002-00, A Subsystem of the Standby Liquid Control System was Inoperable Longer than Allowed by the Plant's Technical Specifications

a. Inspection Scope

The inspectors reviewed the LER dated June 21, 2010, and the applicable PER 225949, including associated apparent cause determination and corrective action plans. The inspectors also reviewed the licensee's human performance analysis and procedure changes resulting from the corrective actions.

As a part of planned work for the U3R14 RFO, the licensee had tagged out the Standby Liquid Control (SLC) System for squib valve replacement. On March 29, 2010, and upon release of the SLC maintenance tagout, operators racked in 3B SLC Pump breaker 3-BKR-063-0006B to restore the SLC system to standby condition in preparation for reactor startup. Unit 3 reactor startup (i.e. – entered Mode 2) occurred on April 7, 2010. On April 20, 2010, operators were conducting surveillance test 3-SI-4.4.A.1, Standby Liquid Control Pump Functional Test, when the 3B SLC Pump failed to manually start. The pump breaker was reported as tripped and further maintenance troubleshooting determined that the breaker racking shaft sleeve was not fully engaged (fully forward), which prevented the breaker from operating. The sleeve was placed in the normal engaged position and subsequent testing on 3B SLC Pump was completed satisfactorily.

The 3B SLC Pump breaker was a model General Electric AK 2A-15. These model breakers were previously identified to have a tendency for this racking shaft sleeve malfunction (i.e. – failure to spring return to full engagement). Therefore, the licensee had implemented a design change to replace this type of breaker which was in progress at the time of this event. The 3B SLC Pump breaker was not scheduled for replacement until the Unit 3 refueling outage in 2012. Rack-in procedures recognized this potential malfunction and required operators to "verify the shaft sleeve slides fully forward" when the racking crank handle was removed. The licensee identified the apparent cause as a failure of the operators to implement the procedure as written and perform proper self-checking and peer checking.

The enforcement aspects of this finding are discussed in Section 4OA7.

b. Findings

One finding of significance was identified (see Section 4OA7 below). This LER is considered closed.

.2 (Closed) LER 05000260/2010-002-00, Failure to Meet the Requirements of Technical Specifications Limiting Condition for Operation Due to Inoperable Primary Containment Isolation Instrumentation

a. Inspection Scope

The inspectors reviewed the LER dated June 25, 2010, and the applicable PER 226666, including associated apparent cause determination, corrective action plans, and human performance analysis.

On April 9, 2010, licensee maintenance personnel performed surveillance testing procedure 2-SR-3.3.6.1.6(4), RCIC Time Delay Relay Calibration, to determine the operability of the Reactor Core Isolation Cooling Steam Line Flow-High Isolation Function for both the A and B Channels. On April 26, 2010, a licensee quality assurance inspector notified Operations personnel that rubber contact boots were left on contacts 1, 2, 3, and 4 of the B Logic relay 2-RLY-71-13A-K32, RCIC High Steam Flow Relay. These contact boots were intended to be used during testing to prevent electrical contacts from making-up which could result in undesirable actions, specifically during the performance of 2-SR-3.3.6.1.6(4). The licensee immediately declared the B Channel inoperable and entered TS 3.3.6.1. Shortly afterward, the licensee verified there was no other testing or maintenance activities in progress that required the contact boots to be in place, and subsequently removed the contact boots which restored operability of the B Channel. The licensee verified that the A Channel remained operable during the entire time the B Channel was inoperable, which meant the RCIC isolation function was still available since only one of two channels was needed to actuate the RCIC isolation logic. The licensee also immediately performed a walkdown of all three units' auxiliary instrument rooms, 4KV electrical board rooms, and EDG buildings to ensure no HFA relays had unauthorized boots installed. The licensee identified the apparent cause of this event as a failure of maintenance personnel to use human performance tools to adequately verify the contact boots were removed as required by surveillance procedure 2-SR-3.3.6.1.6(4). Therefore, the licensee also planned to review and revise applicable procedures to incorporate independent verification requirements for system restoration following the use of contact boots.

The enforcement aspects of this finding are discussed in Section 4OA7.

b. Findings

One finding of significance was identified (see Section 4OA7 below). This LER is considered closed.

.3 (Closed) LER 05000296/2010-003-00 and 05000296/2010-003-01, Multiple Test Failures of Excess Flow Check Valves

a. Inspection Scope

The inspectors reviewed the LER; the LER supplement; and applicable PERs 222850, 223215, and 241921, including associated apparent cause determination and corrective action plans. The inspectors also 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.

On March 26, 2010, the licensee determined that five of 15 EFCVs failed to actuate to their isolation position from a simulated instrument line break during surveillance testing required by TS Surveillance Requirement 3.6.1.3.8. All five failed EFCVs were subsequently replaced. The licensee also expanded the sample size and bench tested another six EFCVs (about 10% of the total EFCV population). No additional EFCV failures were identified. Further investigation by the licensee did not identify any one definitive cause. Two of the EFCVs were obstructed by small foreign particles, but the cause(s) of other three EFCV failures was indeterminate. Also, the licensee's testing methodology was subsequently considered to be error-likely and may have actually resulted in false test failures. The licensee's longer term corrective actions included placing the EFCVs in 10 CFR 50.65(a)(1) status, revising their testing methodology and increased testing of the EFCVs.

The enforcement aspects of this finding are discussed in Section 4OA7.

b. Findings

One finding of significance was identified (see Section 4OA7 below). These LERs are considered closed.

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status reviews and inspection activities.

b. Findings

No significant findings were identified.

.2 Independent Spent Fuel Storage Installation Operations Inspection (IP 60855.1)

a. Inspection Scope

Under the guidance of IP 60855.1, the inspectors reviewed the licensee's procedures and documentation regarding independent spent fuel storage installation (ISFSI) related activities to verify they met the commitments and requirements specified in the HI-STORM 100 Final Safety Analysis Report (FSAR); Certificate of Compliance (CoC) No.1014, including Appendix A, Technical Specifications, and Appendix B, Approved Contents and Design Features; and 10 CFR Part 72.210 for a general licensed ISFSI. In addition, the inspectors interviewed responsible personnel and witnessed selected ISFSI related activities, such as spent fuel transfer, processing, transportation, and dry cask storage operations to ensure that the licensee performed these activities in a safe and compliant manner consistent with approved procedures. In particular, the inspectors also made direct observations and reviewed selected records to ensure the licensee had identified each fuel assembly placed in the ISFSI facility, including the parameters and characteristics of each fuel assembly, and maintained a record of each fuel assembly as a controlled document.

b. Findings

Introduction: A Severity Level IV, cited violation (VIO) of 10 CFR 72.212, Conditions of general license issued under §72.210, was identified by the inspectors for the licensee's repeat failure to adequately control transient combustible materials near the Independent Spent Fuel Storage Installation (ISFSI) in accordance with site procedures.

Description: On August 17, 2010, while performing a routine walkdown of the ISFSI enclosed area, the inspectors observed two unattended vehicles parked near the dry cask storage pad. One of the vehicles was a diesel-powered man-lift (i.e.- JLG) that was located approximately 22 feet from the closest HI-STORM cask loaded with spent fuel. The other vehicle was a Bobcat that was approximately 42 feet from the closest loaded cask. The inspectors contacted responsible licensee personnel who promptly relocated both vehicles from the ISFSI area. Subsequent investigation by the licensee determined that the man-lift contained about 30 gallons of diesel fuel which exceed the allowed transient combustible limits. The quantity of fuel contained by the Bobcat did not exceed allowed limits.

The aforementioned incident was the second occurrence identified by the inspectors of unattended vehicles containing transient combustibles (i.e.- diesel fuel) in excess of allowed limits parked in close proximity to HI-Storm casks loaded with spent fuel. The first occurrence identified by the inspectors was on May 25, 2010 when several unattended vehicles were observed to be parked in close proximity to loaded dry casks. This first occurrence resulted in NCV 07200052/2010002-001, Transient Combustibles Stored Near Independent Spent Fuel Storage Facility in Excess of Amount Allowed for which the licensee initiated PER 231597. The licensee's corrective actions to address this first instance of improper control over transient combustibles within the ISFSI enclosure included removing the vehicles, briefing responsible personnel, and installing a temporary sign on the ISFSI enclosure gate. However, these corrective actions were not effective in preventing a repeat violation because the temporary sign installed on the ISFSI enclosure gate was destroyed by the outside environmental elements. Also, the ISFSI personnel had become accustomed to parking their vehicles in a certain location within the ISFSI enclosure, which had been at a sufficient distance from the closest loaded HI-STORM cask. But as the dry cask campaign of the summer of 2010 progressed, newly loaded casks were subsequently landed on the ISFSI storage pad that eventually resulted in the diesel-driven man-lift being within the 40 foot limit on or about July 16, 2010.

According to SPP-10.10, Control of Transient Combustibles, the requirements and controls for handling and use of transient combustibles in proximity of the BFN ISFSI/Dry Cask Storage Pad were contained within drawings 0-47E201-1 and 0-47E201-2. In particular, drawing 0-47E201-2, ISFSI Fire Hazards Analysis Compensatory Actions, stated that equipment and/or vehicles brought within close proximity to a loaded HI-STORM cask were required to meet the limitations contained in Tables 1, 2, 3 and 4. Table 1, Diesel Fuel, of this drawing contained the proximity limits for specific quantities of diesel fuel. These Table 1 limits established that no diesel fuel could be stored within 20 feet of the edge of a loaded cask; only a maximum of 11.88 gallons could be stored within 20 to 40 feet of a loaded cask: and only a maximum of 211.33 gallons could be stored within 40 to 85 feet of a loaded cask.

Based on visual observations, an examination of HI-STORM transfer records, and a review of drawings 0-47E201-1 and -2, the inspectors determined that the licensee had allowed vehicles with diesel fuel to be stored near a loaded HI-STORM cask in excess of the required limits from about July 16 to August 17, 2010. Specifically, the diesel-powered aerial man-lift (i.e. - JLG) was within 40 feet of a loaded cask, and contained approximately 30 gallons of diesel fuel (on August 17) when the maximum allowed was 11.88 gallons. [Note, since the Bobcat was located in excess of 40 feet away, and contained much less than the allowed 211.33 gallons, it did not exceed allowed combustible loading limits.] These vehicles were being used to support the dry cask campaign conducted from June through August 2010. During this campaign, they were routinely parked within the ISFSI enclosure when not in active use. Upon notification by the inspectors that these vehicles were parked too close, the licensee promptly removed the man-lift vehicle to beyond the 40 foot limit, and posted the entry gate with a permanent sign stating that vehicles must comply with the requirements of drawings 0-47E201-1 and 0-47E201-2. The licensee also initiated PER 245382.

Analysis: The Reactor Oversight Process (ROP) was not used for this issue because inspections of ISFSI activities that do not involve the operating reactor plant are not addressed by the reactor safety cornerstones in the ROP's Significance Determination Process (SDP). Therefore, this issue was evaluated as traditional enforcement as described in the NRC Enforcement Policy. This issue was greater than minor because it was associated with the protection against potential fire damage to the stored spent fuel which if left uncorrected, could become a more significant safety concern since the prolonged presence of combustible materials in the vicinity of the stored spent fuel could increase the vulnerability of the casks to a fire and therefore increase the potential likelihood of fuel damage and/or release during a fire event. Because of the limited quantity of combustibles and the short durations of time they were stored unattended in the vicinity of the loaded dry casks, this finding was not considered to be a significantly appreciable threat for potential exposures to or release of radiation, and was therefore determined to be of Level IV significance based on Example 6.2.d.2 of the NRC Enforcement Policy. No cross cutting aspect was assigned because the ROP was not applicable.

Enforcement: 10 CFR 72.212, Conditions of general license issued under §72.210, section (b)(9) stated, in part, that the licensee shall "Conduct activities related to storage of spent fuel under this general license only in accordance with written procedures." Procedure SPP-10.10, Control of Transient Combustibles, stated that requirements and controls for handling and use of transient combustibles associated with the BFN ISFSI/Dry Cask Storage Pad were contained within drawings 0-47E201-1 and 0-47E201-2. These drawings established limits for the amount of transient combustibles that could be stored in proximity to a loaded HI-STORM cask. In Table 1 of drawing 0-47E201-2, diesel fuel was specifically limited to 11.88 gallons within 40 feet of a loaded cask. Contrary to the above, a diesel-powered man-lift with 30 gallons of diesel fuel was discovered parked approximately 22 feet from a loaded HI-STORM cask on August 17, 2010. For approximately one month, this man-lift had been routinely parked in the same location inside of the minimum allowed 40 feet from a loaded cask. The licensee promptly removed the man-lift vehicle to beyond the 40 foot limit, and posted the entry gate with a permanent sign stating that vehicles must comply with the requirements of drawings 0-47E201-1 and 0-47E201-2. This violation was determined to be a Severity Level IV violation and was entered into the licensee's corrective action program as PER 245382. This is a violation of 10 CFR 72.212 and is identified as VIO 07200052/2010003-001, Repeated Failure to Control Transient Combustibles in Proximity of the Independent Spent Fuel Storage Facility. A notice of violation is attached.

.3 Institute of Nuclear Power Operations (INPO) Plant Assessment Report Review

a. Inspection Scope

The inspectors reviewed the Interim Report for the INPO Evaluation of Browns Ferry Nuclear Plant conducted in July 2010. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC perspectives of licensee performance and to verify if any significant safety issues were identified that required further NRC follow-up.

b. Findings

No findings were identified.

.4 (Closed) URI 05000259, 260, 296/2009008-01, Safety-Related Molded Case Circuit Breakers

On February 9, 2010, the NRC Component Design Basis Inspection (CDBI) inspectors indentified URI 05000259, 260, 296/2009008-01, Safety-Related Molded Case Circuit

Breakers (MCCBs). During the CDBI, the inspectors identified that no records of PM activities existed for four safety-related MCCBs (breakers 607, 705, 712, 715) on 250 VDC Battery Board 1. Furthermore, the inspectors determined that the licensee had not developed and implemented a preventative maintenance (PM) and testing program to detect potential deterioration or provide assure that all installed safety-related MCCBs would perform satisfactorily in service.

To address the inspectors' concern regarding the lack of a PM test program for safety-related MCCBs, the licensee initiated PER 209095 to identify all critical MCCBs that require PMs, initiate PMs as needed, and complete work orders and PMs for all applicable MCCBs. This issue was unresolved pending further inspection to determine the extent of condition and impact of not implementing a PM test program on the reliability of all installed safety-related MCCBs to perform their intended safety functions.

b. Findings

One finding was identified. This URI is considered closed.

Introduction: The inspectors identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," for the licensee's failure to establish a test program for safety-related MCCBs to demonstrate these breakers would be able to reliably perform their intended safety functions.

Description: The inspectors reviewed the licensee's apparent cause evaluation (ACE) and corrective actions for PER 209095. While addressing the extent of this condition, the licensee identified a total of 612 critical MCCBs, many of them safety-related, in both AC and DC applications for which no testing was being performed in accordance with the PM program. Subsequently, PMs were initiated, work orders were scheduled, and testing implemented for the 612 critical MCCBs. As of September 17, 2010, the licensee had tested 461 of the 612 breakers. The licensee planned to be complete with all available on-line MCCBs prior to the Unit 1 refueling outage scheduled in October 2010. All outage-required MCCBs for Unit 3 were completed in the last refueling outage. The Units 1 and 2 outage-required MCCBs will be performed in their upcoming refueling outages in Fall 2010 and Spring 2011, respectively.

As of September 17, 2010, the licensee's expanded PM/testing program had identified 22 failed MCCBs. Inspectors reviewed the licensee's functional evaluations for each of these failures and determined that all MCCBs were capable of performing their safety function (i.e.- to either close, or open, on demand). Also the electrical protective features of the 461 tested MCCBs, except four, were still capable of preventing an electrical fault or overload condition from propagating. The four MCCB exceptions were all related to the 3C EDG. These MCCBs had failed the 300% overcurrent test and would not have protected the cable or end device. The electrical system protection design would have then relied upon the upstream feeder breaker to clear the fault condition. Two of these failed MCCBs were associated with the two redundant fuel oil transfer pumps for the 3C EDG, and thus, a single electrical fault would not have resulted in the 3C EDG being inoperable or unavailable. For the other two MCCBs, failure of either one to clear an electrical fault would have resulted in the upstream breaker tripping to clear the fault condition thereby rendering the 3C Diesel Generator control circuitry, or the water heater and lube oil recirculation pump, non-functional. Thus a single electrical fault condition could have rendered the 3C EDG inoperable and unavailable to support the Unit 3 design basis requirements for onsite emergency AC power. However, the Unit 3 safety design basis, as delineated in FSAR, Section 8.5 Standby AC Power Supply and Distribution, and single failure analysis, established that the standby AC power system of four diesel generators was specifically designed such that a single failure would not jeopardize the effectiveness of the Emergency Core Cooling System (ECCS). Therefore, even though the overload protective feature of these two MCCBs was nonfunctional, a single electrical fault would still have only disabled the 3C Diesel Generator, because the other Unit 3 diesels were electrically and physically separated. Thus, the single failure assumptions of the design basis accident analysis remained valid, and the other three Unit 3 diesel generators would have been capable of supporting the required ECCS safety functions.

Inspectors determined the licensee had not implemented a test program for safety-related MCCBs to detect potential deterioration or to assure that all installed safety-related MCCBs would perform satisfactorily in service. Licensee procedure 0-TI-395, “Breaker Testing and Maintenance Program,” required that critical MCCBs be subject to PM activities, performed every four to six years, such as inspection for overheating, mechanical operation, enclosure inspection, overload trip testing, and instantaneous trip testing. Test procedure ECI-0-000-BKR008, “Testing and Troubleshooting of Molded Case Circuit Breakers and Motor Starter Overload Relays” incorporated these maintenance activities. Also UFSAR 8.6.4.1.1 stated, in part, that zero-resistance short circuits at the battery board or any point downstream can be cleared by the breakers operating within their ratings. To ensure this was satisfied by the installed equipment, degradation of breaker performance should have been detectable and acceptably controlled by periodic testing and preventive maintenance. Additionally, UFSAR 8.5.2.11 stated, in part, that the standby AC power system will meet or exceed the requirements of IEEE-308, Criteria for Class 1E Power Systems at Nuclear Generating Stations. This standard recommended that periodic tests be performed at scheduled intervals to detect deterioration of equipment and to demonstrate operability of components that are not exercised during normal operation.

The inspectors noted that the licensee’s ACE had identified previous opportunities for their corrective action program to recognize the necessity to include safety-related MCCBs in their PM program. In 2002, PER 57643 was initiated for the lack of MCCBs in the PM program. In 2007, PER 131875 was initiated for concerns that some Westinghouse MCCBs were not in the PM program. In both cases, corrective actions only addressed PM requirements, but did not verify MCCBs were actually in the PM program. Also, in September 2008, PER 153450 was initiated for root cause analysis of an ineffective PM program. One of the actions was to define and implement effective equipment reliability strategies for critical components which would have identified the safety-related MCCBs missing from the PM program. The corrective action was not scheduled to be completed until July 14, 2010. Therefore, the licensee determined the apparent cause was that the original corrective action for PER 153450 didn’t adequately resolve the issue of safety-related components left out of the PM program in a timely manner.

<u>Analysis</u>: The inspectors determined that the licensee's failure to include many of their safety-related MCCBs in the breaker test program was a performance deficiency, which resulted in the breakers receiving no planned preventive maintenance or testing. This finding was determined to be of greater than minor significance because it was associated with the Protection Against External Factors attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events, such as fire, that challenge critical safety functions during shutdown as well as power operations. Specifically, many of the installed safety-related MCCBs had received no periodic planned maintenance or tests since installation, in most cases for over thirty years. Based on industry operating experience, this could result in a breaker being slow to trip or sticking in the "on" position after an over-current condition. Since the fault would be cleared by the upstream feeder breaker, this would result in a loss of power to a safety-related component, subsystem, or bus. However, to date, no MCCB failures have resulted in a significant loss or damage of a component, subsystem, or bus. In accordance with IMC 0609, Significance Determination Process (SDP), Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings," this finding required a Phase 3 analysis since the finding represented an increase in the likelihood of a fire caused by an electrical fault at the MCCB compartment with the breaker not opening.

A regional Senior Reactor Analyst performed a Phase 3 Significance Determination Process analysis and characterized the performance deficiency to be of very low safety significance (Green). The dominant hypothetical accident sequence was a fire originating in one of the eighteen upper vertical sections of 480VAC RMOV Board 1A which was not extinguished prior to the cable trays located above the RMOV Board being damaged. In response, operators would attempt to safely shutdown the three units with a mitigation train free of fire damage. However, equipment providing a critical core cooling function would fail and core damage would ensue. The fire scenario was caused by an electrical fault at the molded case circuit breaker compartment and the breaker did not open. The major assumptions of the evaluation included:

- Electrical fault frequency consistent with 14 percent of all motor operated valve failures and these faults developed into fires when the molded case circuit breaker failed to open.

- A failure rate of 4/461 for a molded case circuit breaker failing to open. (This rate was consistent with actual testing results were adequate cable protection was not demonstrated in response to the performance deficiency.)

- An equal probability that the fire, due to the fault, would occur at either the end device, in the cable, or at the molded case circuit breaker compartment.

- Fire development (heat release rates, time to damage, non-suppression probability) consistent with NRC Manual Chapter 0609, Appendix F, for thermo-plastic cable.

- A safe shutdown mitigation failure probability consistent with a single train system for fires in the Control Building and the Reactor Building.

- A safe shutdown mitigation failure probability consistent with that of a non-recoverable Loss of Offsite Power initiator for fires in the Turbine Building.

The cause of this finding was directly related to the cross cutting aspect of Appropriate Corrective Actions in the Corrective Action Program component of the Problem Identification and Resolution area, because the licensee missed an opportunity to implement corrective actions as a result of PER 131875 which identified that certain Westinghouse MCCBs were not in the PM program [P.1(d)].

Enforcement: 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," requires, in part that a test program shall be established to assure that all testing required to demonstrate that components will perform satisfactorily in service is identified and performed in accordance with written test procedures. The test program shall include, as appropriate, operational tests during nuclear power plant operation. Contrary to Criterion XI, since initial startup for all three Browns Ferry units, the licensee failed to establish a test program for their safety-related MCCBs to demonstrate these breakers would perform satisfactorily in service. Because this issue is of very low safety significance and has been entered into the CAP as PER 209095, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. This NCV is identified as NCV 05000259, 260, 296/2010004-03, Failure to Adequately Test Molded Case Circuit Breakers.

.5 (Closed) NRC Temporary Instruction (TI) 2515/177, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems (NRC Generic Letter (GL) 2008-01)"

a. Inspection Scope

The inspectors reviewed the implementation of the licensee's actions in response to GL 2008-01, Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems. The subject systems included the HPCI, core spray, low pressure coolant injection (LPCI), automatic depressurization system (ADS), suppression pool, condensate storage, RHR, and containment spray systems.

The inspectors reviewed the licensing basis of the facility to verify that actions to address gas accumulation were consistent with the operability requirements of the subject systems.

The inspectors reviewed the design of the subject systems to verify that actions taken to address gas accumulation were appropriate given the specifics of the functions, configurations, and capabilities of these systems. The inspectors reviewed selected analyses performed by the licensee to verify that methodologies for predicting gas void accumulation, movement, and impact were appropriate. The inspectors performed walkdowns of selected subject systems to verify that the reviews and design verifications conducted by the licensee had drawn appropriate conclusions with respect to piping configurations and pipe slope which could result in gas accumulation susceptibility.

The inspectors reviewed testing implemented by the licensee to address gas accumulation in subject systems. A selection of test procedures and completed test results were reviewed to verify that test procedures were appropriate to detect gas accumulations that could challenge subject systems. The inspectors reviewed the specified testing frequencies to verify that the testing intervals had appropriately taken historical gas accumulation events as well as susceptibility to gas accumulation into account. The inspectors also reviewed the test programs and processes to verify that they were sensitive to pre-cursors to gas accumulation.

The inspectors reviewed corrective actions associated with gas accumulation in subject systems to verify that identified issues were being appropriately identified and corrected. This review included modifications made to the plant including the installation of additional vent valves. The inspectors reviewed the locations of selected vent valve installations to verify that the locations selected were appropriate based on piping configuration and pipe slopes.

b. Findings and Observations

Introduction: An NRC-identified Green non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified for the licensee's failure to perform functional evaluations in accordance with procedure NEDP-22, "Functional Evaluations," when gas was identified in the High Pressure Coolant Injection (HPCI) System during the Technical Specification required surveillance.

Description: Technical specification (TS) surveillance requirement (TSSR) 3.5.1.1 requires that the licensee verify the piping of each ECCS injection/spray subsystem was filled with water from the pump discharge valve to the injection valve. The associated TSSR implementing procedures directed the licensee to vent each ECCS subsystem to ensure the lines were full of water and, in the event that a gas release was identified during the venting, to initiate a (PER) for system engineers to evaluate the vented gas. Procedure NEDP-22, "Functional Evaluations," provides the requirements for performing these engineering evaluations. Pursuant to NEDP-22, Site Engineering was required to perform a functional evaluation for potentially degraded/non-conforming conditions and when requested by Operations to address operability or functionality issues. If Site Engineering concluded that a functional evaluation was not necessary or the evaluation is to be cancelled, the justification and basis for this conclusion shall be documented in the PER.

The inspectors reviewed eleven PERs generated from May 2009 through January 2010 due to gas discovered during performance of SR 3.5.1.1. for the HPCI system. The timed gas releases during the surveillances ranged from 6 seconds to 7 minutes and 5 seconds. The inspectors determined for these PERs that either Site Operations screened that a potential operability issue existed or there was a potential impact on functionality. For these PERs, procedure NEDP-22 required that Site Engineering shall perform a functional evaluation or provide justification for why a functional evaluation was not necessary. The inspectors' review identified that five out of eleven PERS were closed out to tracking and trending without having a functional evaluation performed. Additionally, there were no documented justifications as to why functional evaluations were not necessary. The licensee entered this issue into their corrective action program as PER 223067 with actions to evaluate the above gas releases as per NEDP-22. Subsequent functional evaluations performed by the licensee concluded that the discovered gas did not impact the operability or functionality of the HPCI system.

Analysis: The failure to perform functional evaluations in accordance with procedure NEDP-22 when gas was identified in the HPCI system during the TS required surveillance is a performance deficiency. This finding is more than minor because it affects the Mitigating Systems Cornerstone objective of ensuring the availability and reliability of safety systems, and is related to the attribute of Procedure Quality (i.e.- Maintenance and Testing Procedures). Specifically, the failure to perform a functional evaluation or adequate justification for not performing one upon identification of gas during venting of the system could affect the operability, availability, and reliability of the HPCI system or could result in missing an opportunity to identify the source of voiding to preclude future inoperability. This deficiency also paralleled Inspection Manual Chapter 0612, Appendix E, Example 4.a, as the licensee routinely did not perform the required functional evaluations. The team assessed this finding using Inspection Manual Chapter 0609, Significance Determination Process, and determined that the finding was of very low safety significance (Green) because subsequent functional evaluations performed showed that the gas voids did not impact the operability of the system.

The cause of this finding was directly related to the cross cutting aspect of Evaluation of Identified Problems in the Corrective Action Program component of the Problem Identification and Resolution area, in that the licensee failed to thoroughly evaluate gas voids such that the resolution addressed causes and extent of conditions, as necessary, and included the failure to thoroughly evaluate for operability and reportability conditions adverse to quality [P.1(c)].

Enforcement: 10 CFR 50, Appendix B, Criterion V, requires, in part, that "activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings." Contrary to the above, on 6/25/2009, 9/9/2009, 11/18/2009, and 1/21/2010, the licensee failed to perform an activity affecting quality in accordance with documented procedures. Specifically, for PERs 174948, 201393, 208522, 214362, and 214361, the licensee did not perform required functional evaluations as required by NEDP-22, Functional Evaluations, when gas voids were identified during venting evolutions of the HPCI ECCS subsystem. The licensee has subsequently performed functional evaluations of the occurrences. Because this finding is of very low safety significance and it was entered into the licensee's corrective action program as PER 223067, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy: NCV 05000259, 05000260, and 05000296/2010004-004, Failure to Perform Functional Evaluations for Gas Identified During Venting.

.6 Follow-up on Alternative Dispute Resolution Confirmatory Orders (IP 92702)

a. Inspection Scope

During the inspection period the inspectors performed a follow-up review of TVA's completion of Confirmatory Order for Office of Investigation Report Nos. 2-2006-025 & 2-2009-003, item numbers 1, 5, 8, and 9:

1. By no later than ninety (90) calendar days after the issuance of this Confirmatory Order, TVA shall implement a process to review proposed licensee adverse employment actions at TVA's nuclear plant sites before actions are taken to determine whether the proposed action comports with employee protection regulations, and whether the proposed actions could negatively impact the SCWE.

5. By no later than sixty (60) calendar days after the issuance of this Confirmatory Order, representatives from the TVA's OGC and Human Resources shall conduct a lessons learned training session

8. By no later than ninety (90) calendar days after the issuance of this Confirmatory Order, TVA shall modify its contractor in-processing program to ensure that a TVA representative provides a presentation regarding the CRP program and the TVA's SCWE policy during the contractor in-processing sessions.

9. By no later than ninety (90) calendar days after the issuance of this Confirmatory Order, TVA shall revise its training program for new supervisors to incorporate a classroom discussion of the NRC's employee protection rule and the Company's policy on SCWE.

Inspectors reviewed training documentation, corrective action documents, procedures, and interviewed licensee personnel as necessary to assess the adequacy of implementation of the Order requirements listed above.

b. Findings

No findings were identified.

.7 Correction of Tracking Number

NRC Inspection Report 05000259/2010003, 05000260/2010003, 05000296/2010003, 05000259/2010501, 05000260/2010501, 05000296/2010501, AND 07200052/2010002 documented a Severity Level IV, non-cited violation (NCV) of 10 CFR 72.212, Conditions of general license issued under §72.210. The identification number of this violation was incorrectly listed as NCV 05000259, 260, 296/2010-004. The correct tracking number is NCV 07200052/2010002-001, Transient Combustibles Stored Near Independent Spent Fuel Storage Facility in Excess of Amount Allowed. This correction is only for administrative purposes.

4OA6 Meetings, Including Exit

.1 Exit Meeting Summary

An interim exit with licensee management and staff was conducted on July 30, 2010, to discuss the results of the TI-177 inspection. Proprietary information reviewed by the team as part of routine inspection activities was returned to the licensee in accordance with prescribed controls.

On October 8, and 22, 2010, the senior resident inspector presented the inspection results to Mr. Keith Polson and other members of the staff, who acknowledged the findings. Proprietary information reviewed by the inspectors as part of routine inspection activities was returned to the licensee or appropriately disposed of.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section 2.3.2 of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

- Unit 3 TS LCO 3.1.7, Standby Liquid Control (SLC) System, in part required that two SLC subsystems be operable in Modes 1, 2, and 3 with an allowed outage time of 7 days for one inoperable SLC subsystem, or place the unit in Mode 3 within 12 hours and Mode 4 within 36 hours. However, during a routine TS required quarterly surveillance test, the licensee discovered that 3B SLC Pump would not start due to the improper engagement of the 480 VAC breaker racking sleeve. This resulted in 3B SLC subsystem being inoperable from April 7 to April 20, 2010, without the licensee taking the required TS 3.1.7 actions. The TS violation was entered into the licensee's CAP as PER 225949. Even though the finding represented an actual loss of safety function of a single train of SLC for greater than its TS allowed outage time, the finding was determined to be of very low safety significance (Green) because the risk significance from the Browns Ferry SDP Phase 2 pre-solved table was green.

- Unit 2 TS LCO 3.3.6.1, Primary Containment Isolation Instrumentation, in part, required that the Reactor Core Isolation Cooling (RCIC) Steam Line Flow-High Isolation Function for both the A and B Channels be operable in Modes 1, 2, and 3 with an allowed outage time of 24 hours for one inoperable channel; or isolate the affected penetration flow path within 1 hour; or place the unit in Mode 3 within 12 hours and Mode 4 within 36 hours. However, the licensee discovered that rubber boots had been inadvertently left installed on the channel B contacts for RCIC Steam Line Flow-High Isolation from April 9 to April 26, 2010. This rendered one of the two TS required channels of the RCIC Steam Line Flow-High Isolation Function as inoperable for a period much greater than the TS allowed 24 hours, without the licensee taking the required TS 3.3.6.1 actions. This TS violation was entered into the licensee's CAP as PER 226666. Even though the finding represented an actual loss of function of a single channel of RCIC Steam Line Flow-High Isolation for greater than its TS allowed outage time, the finding was determined to be of very low safety significance (Green) because the redundant A Channel isolation function remained operable and would have isolated the Unit 2 RCIC system on a RCIC Steam Flow-High signal as needed.

- Unit 3 TS LCO 3.6.1.3, Primary Containment Isolation Valves, required that each Primary Containment Isolation Valve (PCIV) be operable in Modes 1, 2, and 3, and "when the associated instrumentation was required to be operable according to TS LCO 3.3.6.1, Primary Containment Isolation Instrumentation." For one or more inoperable excess flow check valves (EFCVs), TS 3.6.1.3 required the affected flow path to be isolated within 12 hours, or be in Mode 3 in 12 hours and Mode 4 in 36 hours. However, during TS required surveillance testing during the U3C14 RFO, the licensee discovered that five of 15 EFCVs failed to isolate. Based on the existence of multiple failures the licensee concluded that one or more EFCV was inoperable during fuel Cycle 14 operation. This TS violation was entered into the licensee's CAP as PER 222850. The finding was determined to be of very low safety significance (Green) because it did not represent an actual open pathway in the physical integrity of primary containment and did not contribute to the increased potential of an reactor coolant system instrument line break.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Bono, Maintenance Manager
J. Boyer, System Engineering Manager
O. Brooks, Operations LOR Supervisor
W. Byrne, Site Security Manager
P. Chase, Site Nuclear Assurance Manager
J. Colvin, Engineering Programs Manager
P. Donahue, Assistant Engineering Director
G. Doyle, Director Safety and Licensing
M. Durr, Director of Engineering
M. Ellet, Maintenance Rule Coordinator
J. Emens, Licensing Manager
B. Evans, Electrical Maintenance Suprintendent
A. Feltman, Emergency Preparedness Manager
K. Gregory, Director Projects
K. Groom, Mechanical Design Engineering Supervisor
B. Jones, Mechanical Maintenance Superintendent
J. Keck, Reactor Engineering Manager
S. Kelly, Assistant Work Control Manager
R. King, Design Engineering Manager
D. Malinowski, Operations Training Manager
M. McAndrew, Operations Superintendent
O. Miller, Operations Manager
J. Morris, Director Training
W. Nurnberger, Work Control Manager
K. Polson, Site Vice President
E. Quinn, Performance Improvement Manager
J. Randich, Plant General Manager
P. Sawyer, Radiation Protection Manager
T. Smith, Component Engineering Manager
J. Underwood, Chemistry Manager
S. Walton, Instrumentation and Control Superintendent

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000259, 260, 296/2010004-01	URI	Uncontrolled Materials Adversely Impacted the Capability of the EDG Building Emergency Drainage System to Mitigate an Internal Flooding Event (Section 1RO6.1)

07200052/2010003-01	VIO	Repeated Failure to Control Transient Combustibles in Proximity of the Independent Spent Fuel Storage Facility (Section 4OA5.2)

Opened and Closed

05000259, 260/2010004-02	NCV	Failure to Adequately Assess Online Risk Associated With Maintenance Activities on Risk Significant SSCs (Section 1R13)
05000259, 260, 296/2010004-03	NCV	Failure to Adequately Test Molded Case Circuit Breakers (Section 4OA5.4)
05000259, 260, 296/2010004-04	NCV	Failure to Perform Functional Evaluations for Gas Identified During Venting (Section 4OA5.5)

Closed

05000296/2010-002	LER	A Subsystem of the Standby Liquid Control System was Inoperable Longer than Allowed by the Plant's Technical Specifications (Section 4OA3.1)
05000260/2010-002	LER	Failure to Meet the Requirements of Technical Specifications Limiting Condition for Operation Due to Inoperable Primary Containment Isolation Instrumentation (Section 4OA3.2)
05000296/2010-003-00	LER	Multiple Failures of Excess Flow Check Valves (Section 4OA3.3)
05000296/2010-003-01	LER	Multiple Failures of Excess Flow Check Valves (Section 4OA3.3)
05000259, 260, 296/2009008-01	URI	Safety-Related Molded Case Circuit Breakers (Section 4OA5.4)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

0-OI-67, Emergency Equipment Cooling Water System, Rev. 91
0-OI-67/ATT-3 Electrical Lineup Checklist Unit 0, Rev. 83
UFSAR, 10.10 Emergency Equipment Cooling Water System, BFN-22
WO# 09-711108-000, A3 EECW Strainer Leak
WO# 09-714993-000, A2 RHRSW Check Valve Leak
WO# 110934065, D3 EECW Pump Packing Leak
1-OI-71/Att-1, Reactor Core Isolation Cooling System Valve Lineup Checklist, Rev. 11
1-OI-71/Att-2, Reactor Core Isolation Cooling System Panel Lineup Checklist, Rev. 11
1-OI-71/Att-3, Reactor Core Isolation Cooling System Electrical Lineup Checklist, Rev. 11
Drawing 1-47E813-1, Flow Diagram Reactor Core Isolation Cooling System Code Class Boundaries, Rev. 32
3-OI-74/ATT-1, Attachment 1, Valve Lineup Checklist Unit 3, Rev. 86
3-OI-74/ATT-2, Attachment 2, Panel Lineup Checklist, Rev. 86
3-OI-74/ATT-3, Attachment 3, Panel Lineup Checklist, Rev. 87
3-47E811-1, Flow Diagram Residual Heat Removal System, Rev. 64
3-OI-73/Att-1, High Pressure Coolant Injection System Valve Lineup Checklist, Rev. 44
3-OI-73/Att-2, High Pressure Coolant Injection System Panel Lineup Checklist, Rev. 45
3-OI-73/Att-3, High Pressure Coolant Injection System Electrical Lineup Checklist, Rev. 39
3-OI-75, Attachment 1, Core Spray System Valve Lineup Checklist, Effective Date: 8/28/08
3-OI-75, Attachment 2, Core Spray System Panel Lineup Checklist, Effective Date: 4/8/08
3-OI-75, Attachment 3, Core Spray System Electrical Lineup Checklist, Effective Date: 8/28/09
3-OI-75, Attachment 4, Core Spray System Instrumentation Inspection Checklist, Effective Date: 3/27/2010
Drawing 3-47E814-1, Unit 3 Flow Diagram Core Spray System, Rev. 34
CDE #836, Loss of 3A Core Spray Pump Motor due to Loss of 3EA Switchboard Control Power.
Core Spray System health Report (2/1/2010 – 5/31/2010)
Unit 3 CS Open PERs as of August 27, 2010
Unit 3 CS Outstanding WO's as of August 27, 2010
Unit 3 CS Open PMs as of August 27, 2010

Section 1R05: Fire Protection

Fire Protection Report, Volume 1, Fire Protection Plan, Units1/2/3, Rev. 7
Fire Protection Report, Volume 1, Fire Hazards Analysis, Units1/2/3, Rev. 7
Fire Protection Report, Volume 2, Sections IV.7, Pre-Plan No. RX3-519, Rev. 7
Fire Protection Report, Volume 2, Sections IV.8, Pre-Plan No. RX3-565, Rev. 7
0-SI-4.11.B.2.a, Diesel Driven Fire Pump Operability Test, Rev. 45
0-SI-4.11.B.3.a, Weekly Check for Diesel Fire Pump Batteries 1 & 2, Rev. 23
Fire Protection Impairment Permit #'s; 09-1920, 10-2516, 10-2590
Fire Watch Route/Coverage Sheet: Permit/Route # Reactor Bldg. & Turbine Bldg, 9/9/10 to 9/10/10
Roving Fire Watch/Coverage Sheet: Permit/Route # Turbine Bldg. Continuation Sheet, 9/9/10 to 9/10/10

Fire Protection Report, Volume 1, Fire Hazards Analysis, Section 2, Fire Area 19, Rev. 8
Fire Protection Report, Volume 2, Sections IV.12, Pre-Plan No. CB3-593, Rev. 7
Fire Protection Report, Volume 2, Sections IV.3, Pre-Plan No. DG12-565, Revision 8
Fire Protection Report, Volume 2, Sections IV.3, Pre-Plan No. DG12-583, Revision 8
SR247681,SR247729,SR 249063
PER 250380
Fire Protection Impairment Permit (FPIP) 09-1920, App R Safe Shutdown Instructions
Fire Protection Report, Volume 1, Fire Hazards Analysis Units1/2/3, Fire Area 21, Rev. 7
Fire Protection Report, Volume 2, Sections IV.13, Pre-Plans No. DG3-565 and DG3-583, Rev. 8

Section 1R06: Flood Protection Measures

Probabilistic Safety Assessment Internal Flooding Notebook, Rev. 1
Calculation NDN-000-999-2007-0031, Rev. 0
NDN-000-999-2007-0031, IF- BFN Probabilistic Risk Assessment – Internal Flooding Analysis, Rev. 0
0-AOI-100-3, Flood Above Elevation 558', Rev. 33
EPI-0-000-SWZ006, Calibration and Inspection of Station Drainage and Intake Sump Pump Level Switches, Rev. 20
Drawing 0-47W585-1, Rev. 2
Drawing 0-47E851-1, Rev. 29
Drawing 0-47E851-4, Rev. 13
1-ARP-9-7C, Annunciator Response Procedure Panel 9-7, Rev. 21
3-ARP-9-7C, Annunciator Response Procedure Panel 9-7, Rev. 31
1-ARP-9-20A, Annunciator Response Procedure Panel 1-9-20, Rev. 29
SPP-10.7, Housekeeping, Rev. 04
SPP-9.17, Temporary Equipment Control, Rev. 01
0-TI-471, Temporary Equipment Control, Rev. 04
BFN-50-7082, Detailed design Criteria Document, Rev. 15
BFN-50-7067, General Design Criteria Document, Rev. 17
BFN-50-C-7105, Pipe Rupture, Internal Missiles, Internal Flooding and Vibration Qualification of Piping, Rev. 09
CD-Q0303-930993, Calculations for Transient Loads/Materials in Safety-Related Areas, Rev. 02
Licensee Correspondence, BFN-Moderate Energy Line Break (MELB) Flooding Evaluation, dated Sep. 23, 1988
Licensee Correspondence, BFN-Response to Request for Additional Information - Moderate Energy Line Break (MELB) Flooding Evaluation, dated Nov. 29, 1988
Licensee Correspondence, BFN-Moderate Energy Line Break (MELB) Flooding Evaluation, Rev. 01 dated Mar. 24, 1989
05-0842, OE Evaluation/Response for NRC Information Notice 2005-11
05-1886, OE Evaluation/Response for NRC Information Notice 2005-30
WO 111261677, Operability check of plant sump pumps
45N880-12, Conduit & Grounding Floor EL 565.5 & 583.5
0-45E880-13, Conduit & Grounding EL 595.0 & 583.75
0-15N401-1, Yard Lighting Plan
0-15E810-38, Electrical Conduit & Grounding Plant Telecommunications System
0-15E810-1, Conduit & Grounding Plan
0-35N800, Conduit & Grounding Floor EL 550.0 Plan

Section 1R12: Maintenance Effectiveness

SPP-6.6, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting - 10CFR50.65, Rev. 9
0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting - 10CFR50.65, Rev. 34
MREP Meeting dated July 29, 2010
MREP Meeting dated September 29, 2010
U1/2/3 Function 64A-C, Excess Flow Check Valves (a)(1) Plan, Rev 0 (effective date 6/29/10)
U1/2/3 Function 64A-C, Excess Flow Check Valves (a)(1) Plan, Rev 1 (effective date 9/29/10)
PER 241921, Reportable Condition With Documented ACE
Lower Tier Apparent Cause for PER 241921 dated September 21, 2010
NEDO-32977-A, Excess Check Valve Testing Relaxation dated June 2000
TS SR 3.6.1.3.8
TS Bases SR 3.6.1.3.8
TS Amendment No. 268 (Unit 2) and 228 (Unit 3) for Excess Flow Check Valve Surveillance Intervals dated January 29, 2001
PER 222850, Failure of TS 3-SR-3.6.1.3.8 Acceptance criteria
PER 223215, System 64(PCIS) Exceeded Maintenance Rule Performance Criteria
EFCV (Marotta Valve) Testing Scope for U1R8
Maintenance Rule 7th Periodic Report, April 2008 – March 2010
Maintenance Rule 6th Periodic Report, April 2006 – March 2008
Maintenance Rule 5th Periodic Report, April 2004 – March 2006
Unit 1 HPCI (a)(1) plan, Rev. 1
Unit 2 HPCI (a)(1) plan, Rev. 3
CDE 595, U1 HPCI exceeded performance criteria
CDE 626, U1 HPCI exceeded performance criteria
CDE 663, U2 HPCI exceeded performance criteria
CDE 689, U1 HPCI additional unavailability
CDE 690, U2 HPCI additional unavailability
CDE 744, U2 HPCI additional unavailability
CDE 898, U2 HPCI performance criteria not met for return to (a)(2)
Maintenance Rule Expert Panel meeting agenda for 9/10/2010
CDEs 729 and 730, U1 RCIC functional failures
Unit 1 RCIC (a)(1) plan, Rev. 0
CDE 715, U2 Reactor zone exhaust damper component failure
U1,2,3 Secondary Containment (a)(1) plan, Rev. 1
SR 242494, PER 150125 did not address 50.65 (a)(3) 24 month reporting requirement
SR 251600, evaluate need for unavailability performance criteria for System 64
PER 252733, evaluate need for unavailability performance criteria for System 64
PER 246069, 7th MR periodic report not completed by due date.
U2,3 HPCI and RCIC controls (a)(1) plan, Rev. 0

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

PRA Evaluation Response (BFN-0-10-075) dated July 21, 2010
Sentinel Model results dated July 21, 2010
PRA Evaluation Response (BFN-0-10-079) dated July 26, 2010

PRA Evaluation Response (BFN-1-10-080) dated July 28, 2010
PER 225631, DG A Inoperable Due to Low Air Pressure
PRA Evaluation Response BFN-0-10-083
PRA Evaluation Response BFN-0-10-084
Sentinel Risk for 8/05/10
NMG-SPP-07.1, On Line Work Management, Rev. 0
NPG-SPP-07.3, Work Activity Risk Management Process, Rev. 0
0-TI-367, BFN Equipment to Plant Risk Matrix, Rev. 11
NEDP-26, Probabilistic Risk Assessment (PRA), Rev. 2
BFN-0-10-093, PRA Evaluation Request
SR 244354
PRA Evaluation Response (BFN-0-10-102) dated September 20, 2010

Section 1R15: Operability Evaluations

MPI-0-260-DRS001, Inspection and Maintenance of Doors, Rev. 37
PER 223439, BFN-0-DOOR-260-C-RHRSW Door not sealed properly when closed
PER 227113, Past Operability of BFN-0-DOOR-260-C-RHRSW Door Not Sealing Properly
SR 165830, BFN-0-DOOR-260-C-RHRSW
WO 11082297, Repair of BFN-0-DOOR-260-C-RHRSW
WO 09-718875-000, Replace Washers/Shims on RHRSW Door C
WO 08-716513-000, Rework/Repair Door Hardware for RHRSW Door C
WO 09-714922-000, RHRSW Door C Magnetic Lock Sticking
Calculation MD-Q0023-870149, RHRSW Pump Compartment Sump and Sump Pump Capacity, Rev. 14
Calculation MD-Q0023-890078, Pump Performance Analysis for New RHRSW Compartment Sump Pumps, Rev. 2
Drawing 0-37W205-5, Mechanical Pumping Station and Water Treatment – Piping and Equipment, Rev. 7
FSAR Section 1.2, Definition-Probable Maximum Flood, Amendment 21
FSAR Section 1.6, Plant Description-Flooding, Amendment 23
FSAR Section 2.4.2.2.3, Floods, Amendment 19
FSAR Appendix 2.4A, Browns Ferry Nuclear Plant Maximum Possible Flood, Amendment 22
FSAR Section 10.9, RHR Service Water System, Amendment 22
FSAR Section 12.2, Residual Principal Structures and Foundations, Amendment 22
Functional Evaluation for PER 240518, Intake Pumping Station – Residual Heat Removal Service Water (RHRSW) Pump Room Doors – A, B, and D
Functional Evaluation 42331, Intake Pumping Station – Residual Heat Removal Service Water (RHRSW) Pump Room Doors – A, B, and D
General Design Criteria BFN-50-C-7101, Protection from Wind, Tornado Wind, Tornado Depressurization, Tornado Generated Missiles, and External Flooding, Rev. 2
PER 133899, Intake Pumping Station RHRSW Pump Room Doors A, B, and D
PER 240518, Past Operability RHRSW Pump Room Doors A, B, and D
Safety Analysis Review Change Request PER 223614
GE-Hitachi 10 CFR 21 Reportable Condition Notification dated July 1, 2010 regarding "Failure of HPCI Turbine Overspeed Reset Control Valve Diaphragm"
Condition Report # 2010108487
PER 238036, Part 21 - HPCI Turbine Overspeed Reset Control Valve Diaphragm

Functional Evaluation for PER 238036
Calculation B22900803116, Wind Waves
Calculation MD-Q0023-870149, RHRSW Pump Compartment Sump and Sump Pump Capacity, Rev. 14
Calculation MD-Q0023-890078, Pump Performance Analysis for New RHRSW Compartment Sump Pumps, Rev. 2
Drawing 0-37W205-5, Mechanical Pumping Station and Water Treatment – Piping and Equipment, Rev. 7
FSAR Section 1.2, Definition-Probable Maximum Flood, Amendment 21
FSAR Section 1.6, Plant Description-Flooding, Amendment 23
FSAR Section 2.4.2.2.3, Floods, Amendment 19
FSAR Appendix 2.4A, Browns Ferry Nuclear Plant Maximum Possible Flood, Amendment 22
FSAR Section 10.9, RHR Service Water System, Amendment 22
FSAR Section 12.2, Residual Principal Structures and Foundations, Amendment 22
General Design Criteria BFN-50-C-7101, Protection from Wind, Tornado Wind, Tornado Depressurization, Tornado Generated Missiles, and External Flooding, Rev. 2
PER 223614, Potential Error in Calculations for RHRSW Compartment Sump Pumps
SR 164884, Install Detail 5 from Drawing 0-37W205-5
Memo dated September 27, 2010, from Transmission and Reliability Organization (TRO) Engineering Analysis Manager
TRO-TO-SOP-10.128, Browns Ferry Nuclear (BFN) Plant Grid Operating Guide
LCOTR # 0-241-OWA-2010-0121

Section 1R18: Plant Modifications

FSAR Section 10.10, Emergency Equipment Water System
WO 111196942, Implement TACF 0-10-004-067 to monitor dP across EECW flow elements for DG 'D'
WO 111196923, Implement TACF 0-10-004-067 to monitor dP across EECW flow elements for DG 'C'
WO 111164337, Implement TACF 0-10-004-067 to monitor dP across EECW flow elements for DG 'A'
WO 111196876, Implement TACF 0-10-004-067 to monitor dP across EECW flow elements for DG 'B'
TACF 0-10-004-067, Differential Pressure Gauges across the Unit1/2 EDG EECW Supply, Rev. 0
Design Change Notice 69932, Revise RCIC and HPCI Controller Setpoints
PER 221522, Revise RCIC and HPCI Controller Setpoints
PER 246036, BFN U3 Simulator, HPCI isolation.
BFN Setpoint and Scaling Calculation ED-N0071-920225 (RCIC)
BFN Setpoint and Scaling Calculation ED-Q0073-930141 (HPCI)
Surveillance Procedure 1/2/3-SR-3.5.3.3
Surveillance Procedure 1/2/3-SR-3.5.1.8

Section 1R19: Post-Maintenance Testing

WO 09-722790-000, Replace 1B Core Spray Room Cooler Coil
WO 110922826, Verify 1B Core Spray Room Cooler integrity and efficiency.

WO 110922727, Inspect 1B/1D Core Spray Room Cooler Fan
WO 09-718611-035, Disassemble and inspect check valve 1-CKV-067-0656
WO 09-718611-036, Disassemble and inspect check valve 1-CKV-067-0657
WO 0111307032, Relay 2-RLY-099-05AK12F did not de-energize during testing.
PER 245456, Relay 2-RLY-099-05AK12F did not de-energize during testing.
WO 111279809, Troubleshoot/repair A Recirculation Loop flow indication
PER 245818, Unit 3, Voter #2 card failure.
WO 111148386, Replace Diaphragm on 1-PCV-73-0018C, HPCI Turbine Stop Valve Mechanical Trip Hold Valve
1-SR-3.5.1.7, HPCI Main and Booster Set Developed Head and Flowrate Test
WO 10552427, 125 VDC Diesel System Battery D Replacement
WO 111344510, Perform Testing of 0-BATB-254-0000D per ECI-0-254-BAT002 and 0-SR-3.8.6.2 (DG-D)
ECI-0-254-BAT001, Equalize Charging the Diesel Generator Battery Bank
ECI-0-254-BAT002, Replacement and Cleaning of the 125 VDC Diesel Generator Battery Cells
EII-0-000-TCC106, Attachment 2, Wire Lift/Landing Log
0-SR-3.8.4.2 (DG-D), Diesel Generator D Battery Service Test
0-SR-3.8.6.2 (DG-D), Quarterly Check of Diesel Generator D Battery
P&ID 0-761E580-1, 125 VDC System Single Line Diagram, including Service Test Duty Cycle
Capacity Discharge Test Report from C&D Technologies for Purchase Order 103331-1
2-SR-3.5.1.7, HPCI Main and Booster Pump Set Developed Head and Flow Rate Test at Rated Reactor Pressure, Rev. 55
FSAR Section 6.4.1, High Pressure Coolant Injection System
WO 09-721642-000, Disassemble valve bonnet, clean, inspect, refurbish internals, replace gasket
WO 111148387, U2 HPCI – WO for replacing diaphragm on 2-PCV-073-0018C
WO 09-721655-000, HPCI gland seal condensate pump has shaft seal leak
WO 110807313, Slight Oil Leak on 2-PCV-073-0018A HPCI Turbine Stop Valve Pilot Valve

Section 1R22: Surveillance Testing

1-SR-3.5.3.3 – RCIC System Rated Flow at Normal Operating Pressure, Rev. 13
1-SR-3.6.2.1.1 – Suppression Chamber Water Temperature Check, Rev. 00
0-TI-230 - Predictive Monitoring Program, Rev. 23
0-TI-230V - Vibration Program, Rev. 07
NPG-SPP-06.9.1 – Conduct of Testing, Rev.01
0-TI-362 – Inservice Testing of Pumps and Valves, Rev. 24
WO 111005740
SR 245153 - RCIC turbine exceeding 4600 rpm, peak speed was 5500 rpm per dataware.
SR 245167 - Transposition error within surveillance procedure.
SR 243392 – RCIC Instrument drain valve for pump discharge pressure leaking at fitting (1 dpm).
3-SR-3.5.3.3(COMP), RCIC Comprehensive Pump Test
FSAR Section 4.7, Reactor Core Isolation Cooling System, BFN -21
PER 222077, U3 RCIC Comp Test Issues
PER 221267, 3-FCV-71-10 Drawing Discrepancies
PER 221272, 3-ZI-71-10 Position Indication Simulator Fidelity

PER 224035, 3-FCV-71-10 Wiring Scheme
Technical Specifications and Bases 3.5.3, Rev. 53

Section 4OA1: Performance Indicator Verification

Browns Ferry Nuclear Plant Unit 1 MSPI Basis Document, Rev. 5
Browns Ferry Nuclear Plant Unit 2 MSPI Basis Document, Rev. 4
Browns Ferry Nuclear Plant Unit 3 MSPI Basis Document, Rev. 4
NPG Calculation Record of Revision, Calculation Identifier NDN-000-9999-2010-0003, BFN PRA Input to Mitigating Systems Performance Index, Rev. 0
2010 MSPI Derivation Reports (UAI and URI) for Units 1, 2, and 3
EDG System 82 Status Reports for Unreliability and Unavailability
Cause Determination Evaluation (CDE) # 795 C EDG Exceeded Unavailability for Aug. 2009.
Cause Determination Evaluation (CDE) # 886 C EDG Exceeded Unavailability for Feb. 2010.
PER 228153, Revision of EDG Maintenance Rule Numbers for 1st Qtr 2010.
Calculation NDN-000-9999-2010-0003, BFN PRA Input to Mitigating Systems Performance Index, Rev. 0
Cause Determination Evaluation (CDE) 921, 3C RHR Pump Breaker Charging Spring
MSPI Derivation Reports for Units 1, 2, and 3, Various in 2010
SPP-3.4, Performance Indicator Program, Rev. 10
NDN-000-999-2010-0003, BFN PRA Input to Mitigating Systems Performance Index
Unit 1 MSPI Basis Document, Rev. 3
Unit 1 MSPI Basis Document, Rev. 4
Unit 2 MSPI Basis Document, Rev. 2
Unit 2 MSPI Basis Document, Rev. 3
Unit 3 MSPI Basis Document, Rev. 2
Unit 3 MSPI Basis Document, Rev. 3
U1, U2, U3 MSPI summary sheet for 2nd quarter 2010
MSPI Margin to White report, June 2010
MSPI Margin to White report, March 2010
MSPI Margin to White report, 4th quarter 2009
Unit 1,2,3 MSPI Derivation Reports for UAI, June 2010
Unit 3 MSPI Derivation Report for URI, June 2010
Unit 1 MSPI Derivation Report for UAI, April 2010
Unit 3 MSPI Derivation Report for URI, April 2010
CDE 679, B3 EECW pump inoperable
CDE 680, 2A RHRSW inlet header leak
CDE 694, air release valve 0-ARV-023-0587A did not seat
CDE 701, C3 EECW pump tripped on overcurrent
CDE 793, A3 EECW pump inoperable
CDE 804, B1 RHRSW pump failed to start
CDE 877, B3 EECW pump run failure
CDE 893, A3 RHRSW pump unavailability
LCO tracking log from July 1, 2009 to June 30, 2010
PER 175840, unplanned LCO entry C3 EECW pump inoperable
PER 211676, B3 EECW pump failed acceptance criteria
PER 217273, B3 EECW pump failed surveillance

PER 230460, B3 EECW pump declared inoperable
FAQ 473, Add BFN Unit 1 to Table 7 of Appendix F to NEI 99-02

Section 4OA2: Identification and Resolution of Problems

BFN-ODM-4.16, Operator Workarounds/Burdens/Challenges, Rev. 2
BFN Operations Snapshot Self Assessment BFN-OPS-S-10-022, September 7 – 9, 2010
BFN Operations Snapshot Self Assessment BFN-OPS-S-10-002, June 15 – 17, 2010
BFN Operations Snapshot Self Assessment BFN-OPS-S-09-015, August 3 – 7, 2010
BFN Operator Aggregate Impact Unit Performance Indicator, September 9, 2010
LCOTR Log, OWAs, September 15, 2010
NPG-SPP-07.1, On-Line Work Management, Rev. 1
OPDP-1, Conduct of Operations, Rev. 17
PER 247769, Focus Codes for Workarounds, Burdens, and Challenges
PER 225038, MAXIMO Focus Area Codes
PER 218624, Work Order Focus Area Codes and Focus Area Reports
SR 252016, Inconsistent Data for Operator Workarounds, Burdens, and Challenges

Section 4OA3: Event Follow-up

LER 05000296/2010-002-00, A Subsystem of the Standby Liquid Control System was Inoperable Longer than Allowed by the Plant's Technical Specifications
Specification SL-DCN 69492-1, Attachment C, Class 1E, Safety Related Circuit Breakers Listing, Rev. A
0-GOI-300-2, Electrical, Rev. 93
PER 225949, 3B Standby Liquid Control (SLC) Pump Failed to Start
3-SI-4.4.A.1, Standby Liquid Control Pump Functional Test, Rev. 42
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0-TI-509, Spent Fuel Cask Loading Verification, for MPCs #239, 240, 241, 242, 243, and 244
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0-47W452-15, Mechanical Residual Heat Removal System, Rev. 2
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0-47B455-1, Mechanical Vibration Supports, Rev. 0
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0-47W458-2, Mechanical Core Spray System, Rev. 5
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0-47W452-10, Mechanical Residual Heat Removal System, Rev. 16
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1-47E814-1, Flow Diagram Core Spray System, Rev. 23
2-47W2452-8, Mechanical Residual Heat Removal System, Rev. 2
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222343, Errors in OI-73 HPCI Fill and Vent Section
223067, Documentation of Critical Thinking and Past Operability on Gas Venting of ECCS
229030, Revise Isometric Drawings To Denote System High Points
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235900, Drywell Spray Functional Evaluation
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BP-135, Rev 000, Adverse Employment Action
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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