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

October 30, 2009

Mr. Preston D. Swafford
Chief Nuclear Officer and Executive Vice President
Tennessee Valley Authority
3R Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2009004, 05000260/2009004 AND 05000296/2009004

Dear Mr. Swafford:

On September 30, 2009, 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 6, 2009, with Mr. Rusty West 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 and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

In addition to the routine Reactor Oversight Process baseline inspections for all three units, the inspectors continued to conduct augmented inspections on Unit 1 as delineated in NRC letters dated May 16, 2007, December 6, 2007 and May 21, 2008. These Unit 1 augmented inspections were conducted to compensate for the lack of valid data for certain Performance Indicators (PI). These additional inspections are only considered to be an interim substitute for the invalid Unit 1 PIs until complete and accurate PI data is developed and declared valid. However, subsequent to the Unit 1 startup on May 22, 2007, the PIs in the Initiating Events and Barrier Integrity cornerstones, and the Safety System Functional Failure PI of the Mitigating Systems cornerstone, have become valid as acknowledged by the Tennessee Valley Authority letters dated January 7, 2008 and July 11, 2008. Consequently, the only PIs that remain invalid, and thereby subject to the augmented baseline inspection, are the Mitigating Systems Performance Index PIs.

Based on the results of this inspection, no findings of significance were identified. However, three licensee-identified violations which were determined to be of very low safety significance are listed in this report. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy because of their very low safety significance and because they were entered into your corrective action program. If you contest any 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 the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Senior Resident Inspector at the Browns Ferry Nuclear Plant.

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

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

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000259/2009004, 05000260/2009004 and 05000296/2009004
w/Attachment: Supplemental Information

cc w/encl. (See page 3)

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ADAMS: ☐ Yes ACCESSION NUMBER:______________________

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NAME	CStancil	KKorth	CYoung	TRoss	CKontz	EGuthrie
DATE	10/30/2009	10/30/2009	10/30/2009	10/30/2009	10/30/2009	10/30/2009
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Letter to Preston D. Swafford from Eugene Guthrie dated October 30, 2009

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2009004, 05000260/2009004 AND 05000296/2009004

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-259, 50-260, 50-296
License Nos.:	DPR-33, DPR-52, DPR-68
Report No.:	05000259/2009004, 05000260/2009004 and 05000296/2009004
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, 2009, through September 30, 2009
Inspectors:	T. Ross, Senior Resident Inspector C. Stancil, Resident Inspector K. Korth, Resident Inspector C. Young, Senior Resident Inspector (1R04)
Approved by:	Eugene F. Guthrie, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000259/2009004, 05000260/2009004 and 05000296/2009004; 07/01/2009 – 09/31/2009; Browns Ferry Nuclear Plant, Units 1, 2 and 3.

The report covered a three month period of inspection by resident inspectors and a resident inspector from another plant in Region II. 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

None.

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 full rated thermal power (RTP) the entire report period except for one planned downpower. On September 12, 2009, a planned downpower to approximately 70 percent RTP was conducted to perform a control rod sequence exchange, turbine valve testing and main condenser waterbox cleaning. The unit was returned to full RTP on September 14, 2009.

Unit 2 operated at full RTP the entire report period except for five planned downpowers and an unplanned manual reactor scram. Three of the power reductions were conducted to approximately 95 percent RTP to repair moisture separator normal level control valves. These downpowers were conducted on July 6, July 9, and July 24, 2009, and in each case, power was restored to full RTP on the same day. On July 1, 2009, a planned downpower to 60 percent RTP was conducted for a control rod adjustment and returned to full RTP the same day. On July 18, 2009, a planned downpower to 50 percent RTP was conducted to repair a steam leak on a moisture separator, as well as to conduct a control rod adjustment and to clean main condenser water boxes. The unit was returned to full RTP on July 19, 2009. On September 29, 2009, operators inserted a manual scram from 100 percent RTP in response to lowering reactor vessel water level while removing a reactor feedwater pump from service for maintenance. The unit remained shutdown for the remainder of the report period.

Unit 3 operated at full RTP the entire report period except for three planned downpowers, one unplanned downpower and an unplanned manual reactor scram. On July 2, 2009 an unplanned downpower to approx 79 percent RTP was conducted due to rapidly decreasing hotwell level caused by a large condensate leak. The leakage occurred when the 3J Condensate Demineralizer drain valve failed open. Operators isolated the leak and restored plant conditions. The unit was returned to full RTP the same day. On July 13, 2009, a planned downpower to 93 percent RTP was conducted to conduct repairs to the 3C2 high pressure heater drain valve and the unit was returned to full RTP the same day. On August 24, 2009 operators inserted a manual scram from 100 percent RTP in response to lowering reactor vessel water level caused by an inadvertent closure of multiple condensate demineralizer outlet valves due to the online failure of a programmable logic controller (PLC). Once the valves were pinned open to prevent this failure mode, the unit was restarted on August 27 and returned to full RTP on August 29, 2009. On September 12, 2009, the unit was removed from service for a planned repair of a large hydrogen leak on the main generator. Following repairs, the unit was restarted on September 18 and returned to full RTP on September 20, 2009. Finally, on September 28, 2009, a planned downpower to 95 percent RTP was conducted to repair a steam leak from the 3C moisture separator drain valve, the unit was returned to full RTP the same day.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

The inspectors conducted two equipment partial alignment walkdowns to evaluate the operability of selected redundant trains or backup systems, listed below, with the other train or system 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. The documents reviewed are listed in the Attachment.

- Unit 3 Core Spray (CS) System - Division I
- Unit 3 High Pressure Coolant Injection (HPCI)

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

The inspectors completed a detailed alignment verification of the Unit 2 High Pressure Coolant Injection (HPCI) System, using the applicable piping and instrument drawing (P&ID) 2-47E812-1, Flow Diagram HPCI, along with the relevant operating instructions, 2-OI-73 and attachments, to verify equipment availability and operability. The inspectors reviewed relevant portions of the UFSAR and TS. This detailed walkdown also verified electrical power alignment, the condition 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 Reports, Work Orders (WO), and any Problem Evaluation Reports (PERs) that could affect system alignment and operability. The inspectors also performed this equipment alignment using the guidance contained in Operating Experience Smart Sample (OpESS) FY 2009-02, “Negative Trend and Recurring Events Involving Feedwater Systems.”

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Routine Walkdowns

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 three 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 fire fighting equipment, such as fire extinguishers, hose stations, ladders, and communications equipment, was in place.

- Unit 2 Control Building Elev. 593 Including Auxiliary Instrument and Communication Rooms (FA-16)
- Unit 3 Control Building Elev. 593 Including Computer and Auxiliary Instrument Rooms (FA-16)
- Units 1, 2 and 3 Turbine Building/Control Bay Interfaces (FA-25)

b. Findings

No findings of significance 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; and Design Basis Evaluation Report MELB Flood Evaluation Requirements For BFN Unit 2 Restart.

The inspectors performed walkdowns of the internal flood protection features of three risk-significant areas in the Units 1, 2 and 3 Reactor Buildings (519’ elevation), which included, Residual Heat Removal (RHR) and CS pump rooms, HPCI pump rooms and Under-Torus areas 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 any Reactor Building, such as flood level switches; Reactor Building floor drain sump level instrumentation; and Reactor Building bulkhead watertight doors, curbing, and wall penetrations.

The inspectors reviewed selected completed preventive maintenance 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

No findings of significance were identified.

.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-25 located in the yard area east of the reactor building as well as the cable tunnel connecting the Unit 3 turbine building with the switchyard, to verify that the cables were not submerged in water, that cables and/or splices appear 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 are set appropriately to ensure that the cables will not be submerged. Where dewatering devices were not installed; the inspectors ensured that drainage was provided and was functioning properly.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Resident Inspector Quarterly Review

a. Inspection Scope

On August 3, 2009, the inspectors observed the licensed operator requalification as-found simulator evaluation for a crew per Unit 3 Simulator Exercise Guide OPL 178.073, Power Reduction, Recirculation Pump Trip, Reactor Power Oscillations, and ATWS with MSIVs Open.

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 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).

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

.1 Routine

a. Inspection Scope

The inspectors reviewed two specific equipment issues listed below for structures, systems and components (SSC) within the scope of the Maintenance Rule (MR) (10 CFR 50.65) with regard to some or all of the following attributes: (1) work practices; (2) identifying and addressing common cause failures; (3) scoping in accordance with 10 CFR 50.65(b) of the MR; (4) SSC reliability issues; (5) trending key parameters for condition monitoring; (6) SSC unavailability performance; (7) appropriateness of performance criteria in accordance with 10 CFR 50.65(a)(2); (8) system classification in accordance with 10 CFR 50.65(a)(1); and (9) appropriateness and adequacy of (a)(1) goals and corrective actions (i.e., Ten Point Plan). 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.

- Unit 2 Control Rod Drive (CRD) Pump 2A System Unavailability Exceeded Maintenance Rule Performance Criteria (PER 176224)
- Unit 2 Main Steam Relief Valve (MSRV), 2-PCV-1-23, Functional Failure (PER 173480)

b. Findings

No findings of significance 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 four licensee maintenance risk assessments and actions taken to plan and control work activities to effectively manage and minimize risk. The inspectors verified that risk assessments and applicable risk management actions (RMA) were conducted as required by 10 CFR 50.65(a)(4) and applicable plant procedures such as SPP-7.1, Work Control Process; SPP-7.3, Work Activity Work Management Process; and 0-TI-367, BFN Equipment to Plant Risk Matrix. The inspectors also evaluated the adequacy of the licensee's risk assessments and implementation of RMAs.

- C Emergency Diesel Generator (EDG), 1B Standby Liquid Control Pump, 1D Residual Heat Removal (RHR) Pump and Cooler and Main Bank Battery 3 Out of Service (OOS)
- D EDG, B Standby Gas Treatment System and 2C Reactor Feedwater pump OOS
- Unit 1 HPCI, Unit 1 CS Division II Room Cooler, C2 RHR Service Water (RHRSW) pump and C3 Emergency Equipment Cooling Water (EECW) pump OOS
- Main Bank 3 Battery and Battery Board (for cell 88 and 89 replacement), 1C RHR Pump, and 3A Electric Board Room Chiller OOS

b. Findings

No findings of significance were identified

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the five operability/functional evaluations listed below to verify technical adequacy and ensure that the licensee had adequately assessed TS operability. The inspectors also reviewed applicable sections of the UFSAR to verify that the system or component remained available to perform its intended function. In addition, where appropriate, the inspectors reviewed licensee procedure SPP-3.1, Corrective Action Program, Appendix D, Guidelines for Degraded/Non-conforming Condition Evaluation and Resolution of Degraded/Non-conforming Conditions, to ensure that the licensee's evaluation met procedure requirements. Furthermore, where applicable, inspectors 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.

- Units 1/2 and 3 Diesel Generator Building Sumps Backed Up Into Seven Day Fuel Oil Tanks (PERs 154248 and 172516)
- 4KV Bus Tie Board Inadequate Maintenance (PER 176376)
- Units 2 and 3 Failure to Comply with General Electric Services Information Letter (SIL) No. 646, Target Rock Safety Relief Valve Failure to Fully Open (PER 174596)
- 3D EDG Heat Exchanger Low Flow (PER 176519)
- Unit 3 Reactor Core Isolation Cooling (RCIC) Flow Oscillations (PER 200183)

b. Findings and Observations

Introduction: The inspectors identified an issue associated with the operability evaluation of the Unit 3 RCIC System flow oscillations (PER 200183). This issue is being characterized as an unresolved item (URI).

Description: Following the Unit 3 Reactor scram on August 24, 2009, the RCIC system auto-initiated as designed and injected into the vessel restoring reactor water level. The RCIC pump ran for approximately 2 ½ minutes. Subsequent review of RCIC system operating parameters by the system engineer revealed an unexpected level of instability in system flow and turbine control system response. Unit 3 RCIC flow was determined to be oscillating from approximately 300 gallons per minute (gpm) to 900 gpm on a five second period. The cause of these oscillations was not identified. The licensee determined that RCIC was operable but degraded based on an average flow greater than the minimum required 600 gpm, adequate margins to the over-speed and high turbine exhaust pressure trips, and because the oscillations appeared stable with no apparent divergence in amplitude or frequency. However, the licensee's functional evaluation was based on turbine performance for a very short period of time and concluded that this performance would not change during the required mission time of 24 hours or over the range of reactor pressures RCIC would be required to operate under.

Unit 3 was restarted following the scram on August 27, 2009, but was removed from service on September 12, 2009, to repair a Main Generator hydrogen leak. During this maintenance outage the RCIC turbine electronic governor regulator (EGR) was replaced and the flow control loop was calibrated. Subsequent post-maintenance testing (PMT) included operating RCIC in the injection mode, which was completed with no oscillations noted. Based on an acceptable PMT, Unit 3 RCIC was declared fully operable and returned to service after restart of Unit 3 on September 18, 2009.

The EGR that was replaced following the August 27 scram had been installed since March 2006. This EGR had experienced similar flow oscillations while in the reactor vessel injection mode following a Unit 3 scram on February 9, 2007, (PER 119628 and PER 168144). The licensee's corrective actions to address the Unit 3 RCIC flow oscillations following the 2007 scram, included manual stroking of the RCIC governor valve, control loop calibration, repair of a broken terminal screw and adjustment of the compensating needle valve on the EGR. However, these corrective actions did not include replacing the EGR, and the PMT only operated RCIC in the Condensate Storage Tank (CST) recirculation mode (not in the reactor pressure vessel injection mode). At that time, the licensee concluded their corrective actions were sufficient to resolve the flow oscillations, and they believed RCIC operability was adequately demonstrated by the PMT (i.e., CST recirculation). Following the Unit 3 scram on August 27, 2009, it was revealed that the previous corrective actions and testing did not resolve the excessive flow oscillations.

The inspectors questioned the basis of the licensee's past operability determination which presumed that the flow oscillations would remain constant over a 24 hour mission time, and at different pressure conditions in the reactor vessel, without knowing the definitive cause of the oscillations. Further review of the licensee's methodology used for determining whether the 600 gpm minimum flowrate TS requirement 3.5.3.3 was met, during the high frequency flow oscillations between 300 gpm and 900 gpm, will be conducted.

The licensee has developed a corrective action contained in PER 200183 to have the EGR vendor conduct additional testing and/or inspection of the replaced EGR to determine the cause of the oscillations. Following the EGR vendor evaluation and the licensee's assessment of past operability, the inspectors will review the results. Additional information from the licensee regarding the root cause of the flow oscillations, and past operability determinations, will be needed to resolve the inspectors' concerns. Consequently, pending additional information from the licensee and further review by the NRC, this issue will be identified as URI 05000296/2009004-01, Unit 3 Reactor Core Isolation Cooling Pump Flow Oscillations.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the five 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 SPP-6.3, Post-Maintenance Testing, and MMDP-1, Maintenance Management System. Furthermore, the inspectors reviewed problems associated with PMTs that were identified and entered into the CAP.

- Unit 2: PMT for Reactor Core Isolation Cooling Pump Following Turbine EGM and RGSC Replacement per WO 09-722264-000 and 2-SR-3.5.3.3, RCIC System Rated Flow at Normal Operating Pressure
- Unit 3: PMT for failure of 3-FCV-71-9, RCIC Trip and Throttle Valve, to trip in accordance with 3-SR-3.5.3.3, RCIC System Rated Flow at Normal Operating Pressure and Work Order 09-719914-002.
- Common: PMT for C3 Emergency Equipment Cooling Water Pump, 0-PMP-023-0091 per WO 09-720669-000 and 3-SI-4.5.C.1(2), EECW Pump Operation.
- Unit 3: Reactor Pressure Vessel Injection PMT for Reactor Core Isolation Cooling Pump Following Turbine EGR Replacement per WO 09-721447-000 and 3-OI-71, Reactor Core Isolation Cooling System.
- Unit 3: 3D EDG PMT Following Cooler maintenance per 3-SR-3.8.1.1(3D), Diesel Generator 3D Monthly Operability, and WO 09-719495-000

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

.1 Unit 3 Forced Outage to Repair Main Generator Hydrogen Leak

a. Inspection Scope

Unit 3 was shut down on September 12, 2009, to repair a hydrogen leak on the main turbine #9 bearing seal to the lube oil system. The seal had started to leak following the Unit 3 manual scram on August 24, 2009, (see Section 4OA3.1). The unit subsequently entered Mode 4 to repair the seal and to correct flow oscillations in the RCIC System that were evident during reactor pressure vessel injection following the August 24 trip. Unit 3 was restarted on September 18 and reached full RTP on September 20, 2009. During this short 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. Some of the more significant outage activities monitored, examined and/or reviewed by the inspectors were as follows:

- Reactor Shutdown and cooldown activities per 3-GOI-100-12A, Unit Shutdown from Power Operations to Cold Shutdown and Reduction in Power During Power Operations
- Control of Cold Shutdown (Mode 4) conditions, and critical plant parameters
- Plant Operations Review Committee (PORC) event review and restart meeting in accordance with SPP-10.5, Plant Operations Review Committee
- Reactor startup and power ascension activities per 3-GOI-100-1A, Unit Startup

- Outage risk assessment and management per SPP-7.2, Outage Management
- Control and management of forced outage and emergent work activities per SPP-7.2

The inspectors reviewed PERs generated during the Unit 3 forced outage, and attended Corrective Action Review Board (CARB) and/or PER Screening Committee (PSC) meeting(s) to verify that initiation thresholds, priorities, mode holds, and significance levels were assigned as required.

b. Findings

No findings of significance were identified.

.2 Unit 2 Forced Outage Due To Loss of Feedwater

a. Inspection Scope

Unit 2 was manually scrammed on September 29, 2009, due to rapidly decreasing reactor vessel water level (RVWL) caused by the loss of the 2A Reactor Feedwater pump (RFP) and 2A Condensate Booster pump. Following the scram, the licensee decided to cool down to Mode 4 on September 30 to repair a 2B Steam Jet Air Ejector Isolation Valve. The unit remained in Mode 4 for the remainder of the report period. During this 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. Some of the more significant outage activities monitored, examined and/or reviewed by the inspectors were as follows:

- Reactor shutdown and cooldown activities per 2-GOI-100-12A, Unit Shutdown from Power Operations to Cold Shutdown and Reduction in Power During Power Operations
- Control of Cold Shutdown (Mode 4) conditions, and critical plant parameters
- PORC event reviews and restart meetings in accordance with SPP-10.5
- Outage risk assessment and management per SPP-7.2
- Control and management of forced outage and emergent work activities per SPP-7.2

The inspectors reviewed PERs generated during the Unit 2 forced outage and attended PSC and CARB meetings to verify that initiation thresholds, priorities, mode holds, and significance levels were assigned as required.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

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

- 3-SI-4.4.A.1, Standby Liquid Control Pump Functional Test
- 3-SR-3.5.1.6(CSII), Core Spray Flow Rate Loop II

Routine Surveillance Tests:

- 3-SR-3.8.1.1(3B), Diesel Generator 3B Monthly Operability Test
- 2-SR-3.3.5.1.6(B I), Functional Testing of RHR Loop I Pump and Minimum Flow Valve Logic

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

On July 16, 2009, the inspectors observed an Emergency Preparedness drill that contributed to the licensee's Drill/Exercise Performance and Emergency Response Organization PI measures to identify any weaknesses and deficiencies in classification and notification activities. The inspectors observed emergency response operations in the Unit 2 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 EPIPs. The inspectors also attended the licensee critiques of the drill to compare any inspector-observed weakness with those identified by the licensee in order to verify whether the licensee was properly identifying weaknesses.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

Cornerstone: Mitigating Systems

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the Performance Indicators (PI) listed below, including procedure SPP-3.4, Performance Indicator for NRC Reactor Oversight Process for Compiling and Reporting PIs to the NRC. The inspectors reviewed the raw data for the PIs listed below for the third quarter of 2008 through second quarter of 2009 and discussed the methods for compiling and reporting the PIs with cognizant licensing, engineering, and maintenance rule personnel. The inspectors also independently screened maintenance rule cause determination and evaluation reports and calculated selected reported values to verify their accuracy. The inspectors compared the licensee's raw data against graphical representations and specific values reported to the NRC for the second quarter 2009 PI report to verify that the data was correctly reflected in the report. The inspectors also reviewed the past history of PERs for any that might be relevant to problems with the PI program. The inspectors reviewed Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, to verify that industry reporting guidelines were applied. Although the Unit 1 MSPIs would not be considered valid until the third quarter of 2010, the inspectors conducted the inspection described above for the Unit 1 data as part of the Unit 1augmented baseline inspection plan described in NRC letter dated May 21, 2008.

- Unit 1 Mitigating Systems Performance Index - High Pressure Coolant Injection
- Unit 2 Mitigating Systems Performance Index - High Pressure Coolant Injection
- Unit 3 Mitigating Systems Performance Index - High Pressure Coolant Injection
- Unit 1 Mitigating Systems Performance Index - Reactor Core Isolation Cooling
- Unit 2 Mitigating Systems Performance Index - Reactor Core Isolation Cooling
- Unit 3 Mitigating Systems Performance Index - Reactor Core Isolation Cooling
- 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)

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

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

As required by Inspection Procedure 71152, “Identification and Resolution of Problems,” and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee’s corrective action program (CAP). This review was accomplished by reviewing daily PER report summaries, periodically attending CARB and 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 CAP, 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 (OWA) 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 inspector walked down selected OWAs, and verified the ongoing performance, and/or feasibility of, the required actions. For selected OWAs, the inspector reviewed the applicable PER, including the associated functional evaluation and corrective action plans (both interim and long term). Lastly, the inspector reviewed corrective action program documents related to the OWA program initiated in response to previous NRC inspection reports, self-assessments and audits.

b. Findings and Observations

No findings of significance were identified. However, the inspectors had the following observations:

Several OWAs required operation of components outside their normal configuration which was controlled by either a work order or a caution order. However, no 10 CFR 50.59 screening or evaluation had been conducted. Examples included a 10 step procedure to compensate for fouling of the waste collector filter (0-077-OWA-2008-0120, WO 08-720168); maintaining Unit 3 Drywell (DW) Equipment Drain Sump isolation valve closed due to leak-by of system check valves (3-77-OWA-2009-0050, WO 09-715173-000); maintaining Potable Water Head Tank Make-up Isolation Valve closed due to a failed level control valve (0-029-OWA-2008-0133, Caution Order 0-2008-1, Section 0-

029-0002); maintaining a Unit 1 condensate demineralizer valve closed due to leak-by of another valve (1-002-OWA-2008-0160, Caution Order 1-2008-1, Section 1-077-0022); maintaining nitrogen supply valve to Unit 1 DW closed due to a leaking relief valve (1-076-OWA-2007-0131, Caution Order 1-2007-1, Section 1-076-0009C); and keeping a Unit 3 RWCU demineralizer drain valve closed due to valve leakage on another valve (3-069-OWA-2009-0046, Caution Order 3-2009-1, Section 3-069-0004B). The licensee entered this observation into their corrective action program as PER 178260. The inspectors concluded that none of the aforementioned instances involved safety-related or risk significant equipment in a way that would constitute a violation of regulatory requirements.

The Conduct of Operations procedure, OPDP-1, required that the time to take actions for operator workarounds, burdens and challenges were to be tracked to quantify the impact to each watch station. Of the 30 OWAs reviewed, only 15 had a time listed and few identified which watch station was impacted. The licensee entered this observation into their corrective action program as PER 178254.

Work Orders written on equipment deficiencies that resulted in OWAs were to be given a focus code (i.e., W1, W2 or W3) to ensure appropriate priority was assigned and to allow for generation of an OWA report showing all open OWA WOs. Inspectors found six examples of WOs without the appropriate focus code assigned. The licensee entered this observation into their corrective action program as PER 178251.

The inspectors specifically reviewed the licensee's effectiveness in correcting recurring deficiencies in the OWA program. NRC Inspection Report (IR) 05000259/2008-004 had noted similar deficiencies as those described above (e.g., OWA instructions modified operating procedures without the proper reviews and approvals provided by a procedure change process or a 10 CFR 50.59 screening; times not assigned to all OWAs; WO focus code report not containing all OWAs; etc.). In 2008, the licensee initiated PER 151424 to address these and other issues. A licensee Quality Assurance (QA) Audit (SSA0903) conducted in April of 2009 found Focus Code W1, W2 and W3 WOs did not agree with the OWA Log, and WOs were not listed for all OWAs. PER 167938 was written to address the QA finding. Self Assessment BFN-OPS-S-09-009 was conducted in April 2009 and found that mission times were not listed for several OWAs, some OWA entries did not list the Work Order, inconsistencies existed between the LCO Tracking Log and Select Area Focus Area Report for OWAs, and that PER 151424 was ineffective in some areas. The licensee initiated PER 169116 as a result of the self-assessment. The licensee conducted another self assessment (BFN-OPS-S-09-015) in August 2009 on the OWA program which found similar issues and concluded that PER 169116 had been ineffective in correcting the identified issues. The licensee initiated PER 178264 on CAP ineffectiveness in correcting OWA deficiencies.

4OA3 Event Follow-up

.1 Unit 3 Manual Reactor Scram

a. Inspection Scope

On August 24, 2009, operators manually scrammed Unit 3 from 100 percent RTP due to rapidly decreasing reactor vessel water level (RVWL) when the 3A and 3B Condensate Booster pumps tripped from low suction pressure. The loss of both condensate booster pumps was caused by an unexpected closure of multiple condensate demineralizer outlet valves. The licensee's cause investigation concluded that five of nine condensate demineralizer outlet valves spontaneously closed due to a system communication fault to the Programmable Logic Controller (PLC) for the condensate demineralizer system. The resident inspectors responded to the control room and verified that the unit was in a stable Mode 3 (Hot Shutdown) condition. The inspectors also confirmed that all safety-related mitigating systems and automatic functions operated properly. Furthermore, the inspectors evaluated safety equipment and operator performance before and after the event by examining existing plant parameters and alarms, recorder strip charts, plant computer historical data displays, operator logs, and the critical parameter trend charts and sequence of events printout contained in the licensee's post-trip report. The inspectors also interviewed responsible on-shift Operations personnel and examined the implementation of applicable ARPs, AOIs, and EOIs, particularly 1-AOI-100-1, Reactor Scram. Furthermore, the inspectors reviewed and verified that the NRC required notifications were made in accordance with 10 CFR 50.72.

b. Findings

No significant findings were identified.

.2 Unit 2 Manual Reactor Scram

a. Inspection Scope

On September 29, 2009, operators manually scrammed Unit 2 from 100 percent power due to rapidly decreasing RVWL when the 2A Condensate Booster pump and 2A RFP tripped from low suction pressure. The low suction pressure conditions occurred while operators were attempting to remove the 2B RFP from service for maintenance while the 2B Condensate pump and 2C Condensate Booster pumps were already out of service for planned maintenance in accordance with existing procedures and work schedule. When the 2B RFP minimum flow valve opened as designed, the subsequent increased flow exceeded flow capacity of the operating condensate pumps. During the transient, RVWL reached Level 2 and both HPCI and RCIC started per design. But, an unknown, pre-existing failure of the RCIC electronic governor module (EGM) caused the RCIC pump to immediately shutdown after actuation. The resident inspectors responded to the control room and verified that the unit was in a stable Mode 3 (Hot Shutdown) condition. The inspectors also confirmed that all other safety-related mitigating systems and automatic functions operated properly. Furthermore, the inspectors evaluated safety equipment and operator performance before and after the event by examining existing plant parameters and alarms, recorder strip charts, plant computer historical data displays, operator logs, and the critical parameter trend charts and sequence of events printout contained in the licensee's post-trip report. The inspectors also interviewed responsible on-shift Operations personnel and examined the implementation of applicable ARPs, AOIs, and EOIs, particularly 1-AOI-100-1, Reactor Scram. Furthermore, the inspectors reviewed and verified that the NRC required notifications were made in accordance with 10 CFR 50.72.

b. Findings

No significant findings were identified.

.3 (Closed) LER 50-260/2009-002, Leak In An ASME Code Class 1 Reactor Pressure Boundary Pipe

a. Inspection Scope

The inspectors reviewed the LER, dated July 30, 2009, and the applicable PER 172551, which included the associated apparent cause analysis and corrective action plans. The initial follow-up of this event by the inspectors was conducted as part of the IP 71111.20 inspection activities of IR 05000259/2009003, 05000260/2009003 and 05000296/2009003 during the U2C15 refueling outage.

On May 31, 2009, during an ASME Section XI System Leakage Test of the Unit 2 Reactor Pressure Vessel (RPV), the licensee identified a small reactor coolant pressure boundary (RCPB) leak from a valve body plug weld that could not be isolated from the RPV. The tapered plug was an ASME Code Class 1 component welded into the body of RHR Shutdown Cooling Root Valve (2-SHV-074-049), the first valve from the RPV. The plug had been installed in the place of a previously removed leak-off line in February 1992. Subsequent weld excavation by the licensee determined the through-wall leak was from a small pin-hole that had originated from a defect at the location of the first pass (root) weld which was not identified during initial non-destructive testing. The licensee's apparent cause investigation determined that the cause of the defect was the use of a gas-tungsten weld process with the presence of moisture at the bottom of the weld. The gas-tungsten weld process was an industry standard at the time, but has since been determined to be susceptible to moisture affects, and has been replaced by the shielded-metal arc process. The licensee postulated that this defect slowly propagated over the past 17 years of plant operation and just became evident during the U2C15 RPV pressure test.

The reactor coolant system (RCS) unidentified leakrate during the prior Unit 2 reactor operating cycle was a steady 0.03 to 0.04 gpm. Also, no leakage was identified from 2-SHV-074-049 during the Unit 2 post shutdown leak inspection walkdown while in Mode 3. However, during the Unit 2 hydrostatic pressure test (i.e.- ASME Section XI System Leakage Test), while in Mode 4, operators observed water spraying from the plug on 2-SHV-074-049, which was subsequently estimated to be in excess of 0.25 gpm. Based on this information, the inspectors concluded that the RCPB leak did not occur until after the unit was in mode 4. The TS 3.4.4 LCO requirement for no allowed RCPB leakage was only applicable for Modes 1, 2 and 3.

The plug weld leak was repaired during the U2C15 refueling outage by excavating the weld flaw area to re-establish the as-designed socket joint configuration, and then re-welding using the shielded metal process. The weld was successfully tested by non-destructive methods and completion of the RPV pressure test. Similar Unit 1 and Unit 3 valve plug modifications were evaluated by the licensee and determined to be free of moisture-induced weld problems.

b. Findings

The TS 3.4.4 LCO requirement for no allowed RCPB leakage is only applicable for Modes 1, 2 and 3, therefore no significant findings or violations of NRC requirements were identified. This LER is considered closed.

.4 (Closed) LER 05000260/2009003-00: Main Steam Relief Valve As Found Setpoint Exceeded Technical Specification Lift Pressure

The inspectors reviewed the LER dated August 7, 2009, and the applicable PER 175990, including associated apparent cause determination and corrective action plans. The inspectors also reviewed the fuel vendor's evaluation, "BFE2-15 ASME and ATWS Overpressurization Analysis With As-Tested Main Steam Relief Valve (MSRV) Setpoint Data," dated July 29, 2009.

Following the U2C15 refueling outage, the licensee removed and lift tested the 13 MSRVs that had been in service during the U2C15 operating cycle. During this surveillance testing, the as-found U2C15 lift setpoints for seven of the 13 MSRVs exceeded the TS 3.4.3 allowed limit of plus 3 percent of the TS required setpoint. The cause of the MSRV as-found setpoints being outside their TS limits was determined to be corrosion bonding between the pilot valve seat and disc, which continues to be a recognized industry problem. The failure of these MSRVs to lift within the allowed setpoint limits constituted a condition prohibited by TS 3.4.3. To address the potential safety consequences, the licensee conducted a reactor vessel overpressure evaluation by re-running the U2C15 Reload ASME Overpressure and Plant Transient analysis using the as-found MSRV lift setpoint data. From the results of this evaluation, the licensee concluded that the as-found condition of the MSRVs from U2C15 would have been sufficient to fulfill their overpressure relief safety function during design basis over-pressure transient events.

The licensee also conducted an anticipated transient without scram (ATWS) overpressure analysis for the most limiting event assuming the same as-found MSRV lift setpoint data. This analysis demonstrated compliance with the ASME Section III Service Level C Limit for emergency events.

b. Findings

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

.5 (Closed) LER 05000259, 05000260, 05000296/2009003-00, A Train Standby Gas Treatment System Inoperable Longer Than Allowed By the Technical Specifications

a. Inspection Scope

On November 30, 2008, during normal operation of the ‘A’ Standby Gas Treatment (SBGT) train to vent the drywell, annunciator 1-XA-55-22B-11, SGT Filter Bank ‘A’ Heating Element Power Loss, was received. The operators misdiagnosed the issue as a malfunction of the alarm circuit rather than a failure of one of the three relative humidity heaters in the train. All three heaters were required to meet the TS requirement to maintain 40 KW of heater capacity. During trouble shooting performed on January 22, 2009, the licensee found the RH heater relay coil circuit was open and relay coil failed, but operability of the system was not re-evaluated. Following initiation of a PER by Operations requesting further guidance on operation of the SBGT system with this locked-in alarm, plant Engineering determined that this train of SBGT was inoperable. On June 19, 2009, plant Engineering notified Operations that the C-phase relative humidity heaters were not functional and operations declared SBGT train ‘A’ inoperable. Units 1, 2, and 3 were in a condition prohibited by the plant's TSs since the licensee had not taken the required action to place the units in Mode 3 in 12 hours and Mode 4 in 36 hours if a train of SBGT was inoperable for greater than seven days.

The cause of the event was inadequate investigation into the cause of the original alarm and its potential impact on the operability of the system. Corrective actions included replacement of the relay, revision of the surveillance procedure and revision to the annunciator response procedure. This event was reviewed by the inspectors and documented in Inspection Report 05000259, 260, and 296/2009-006. A non-cited violation identified as 05000259, 260, and 296/2009006-01, Standby Gas Treatment Subsystem ‘A’ Inoperable Beyond the Technical Specification Allowed Outage Time, was issued as a result. The inspectors reviewed the LER and associated PER 174416 and apparent cause analysis.

b. Findings

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

.6 (Closed) LER 05000260/2009004-00, Technical Specification Shutdown Due to Rise in Unidentified Drywell Leakage

a. Inspection Scope

The inspectors reviewed the LER dated August 10, 2009, and applicable PERs (e.g., 174596 and 173480), which included the associated root cause determination and corrective action plans.

On June 10, 2009, during scheduled TS required surveillance testing in accordance with 2-SR-3.4.3.2, MSRV Manual Cycle Test, one of the Unit 2 MSRVs (i.e., pressure control valve 2-PCV-1-23) failed to fully open and then failed to reseat. Then on June 11, 2009, the Unit 2 unidentified RCS leakrate suddenly increased from essentially zero to approximately four gpm, which exceeded the TS LCO 3.4.4 limit of no more than a two gpm increase over the previous 24 hours. Pursuant to Technical Specifications Action Statement (TSAS) 3.4.4.C, operators promptly shutdown Unit 2 (entered Mode 3), then cooled down to Mode 4. During the shutdown, the partially stuck open MSRV (2-PCV-1-23) finally reseated itself. The source of the increased unidentified leakrate was subsequently determined to be the partially stuck open MSRV (2-PCV-1-23) in concert with a mechanical failure of the downstream tailpipe vacuum breakers that resulted in a direct release into the drywell. The licensee replaced the pilot valve on 2-PCV-1-23 and restarted Unit 2 on June 15. However, during the PMT of 2-PCV-1-23 on June 16, the MSRV became partially stuck open again. Unit 2 was promptly shutdown and the MSRV reseated itself.

Subsequent MSRV disassembly and troubleshooting by the licensee determined that the original manufacturer threaded main piston-to-main stem joint had fretted, damaging the mating threads and resulted in the main piston and/or shaft becoming cocked by approximately ¼”, thus causing the main piston to bind during valve cycling. The susceptibility of Target Rock Two-Stage MSRVs to experience this threaded joint degradation was specifically addressed by General Electric Service Information Letter (GE SIL) 646, Target Rock Safety Relief Valve Failure To Fully Open. However, the licensee had failed to implement the GE SIL inspections and modifications within the recommended time period. As a consequence, MSRV 2-PCV-1-23 failed to fully open and reseat during routine surveillance testing due to the failure mechanism described by GE SIL 646.

b. Findings

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

.7 (Closed) LER 05000260/2009-005, Reactor Motor Operated Valve Board and Residual Heat Removal Subsystem Inoperable Longer than Allowed by the Plant’s Technical Specifications

a. Inspection Scope

The inspectors reviewed the LER dated September 16, 2009, and the applicable PER 176648, including associated apparent cause determination and corrective action plans.

On July 18, 2009, while performing the Monthly Emergency Control Switch verification surveillance, operators identified that the Manual/Auto Transfer Switch (43 Switch) on 480V RMOV Board 2D was in MANUAL. Upon notification of the switch in the MANUAL position Operations declared 2D 480V RMOV Board inoperable and entered 7 day Technical Specification LCOs 3.8.7.C, Electrical Distribution System - Operating, and 3.5.1.A, Emergency Core Cooling System - Operating. The auto transfer function of this RMOV board was required to be maintained per TS to maintain both the board and RHR Loop I (LPCI Mode) OPERABLE. Subsequently, Operations returned the switch to the AUTO position and exited all associated TSASs. Although the time that the switch was mispositioned could not be definitively established, the licensee assumed the switch had been in MANUAL since the unit restarted from a refueling outage on June 19, 2009. Therefore, Unit 2 was in a condition prohibited by the plant's TS since the licensee had not taken the required action to place the units in Mode 3 in 12 hours and Mode 4 in 36 hours if one low-pressure ECCS subsystem is inoperable for greater than seven days.

The apparent cause of this event was not conclusively determined, but the licensee concluded the most likely possibility was an accidental bumping of the Auto-Manual Transfer (43) Switch on 480V RMOV Board 2D causing it to swap from the auto to the manual position. Long term corrective actions, taken or planned, include installation of a protective cover over the switch to prevent inadvertent operation and revision to plant operating procedures to verify switch positions prior to changing operating modes to where the equipment would be required to be operable. The position of the Auto-Manual transfer switch was being verified shiftly until long term corrective actions were completed.

b. Findings

This event was determined to be a licensee-identified finding which involved a violation of TS 3.5.1, Emergency Core Cooling System - Operating. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is 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 and 10 CFR 72.48 Evaluations Review

a. Inspection Scope

Under the guidance of IP 60855.1, the inspectors observed operations involving independent spent fuel storage installation (ISFSI), interviewed personnel and reviewed the licensee's documentation regarding ISFSI related programs and procedures for fulfilling the commitments and requirements specified in the Safety Analysis Report (SAR), Certificate of Compliance (CoC), 10 CFR Part 72, the Technical Specifications (TS), any related 10 CFR 72.48 evaluations, and 10 CFR 72.212(b) evaluations for general licensed ISFSIs. In addition, the inspectors observed selected ISFSI related activities and conducted independent evaluation to ensure that the licensee performed spent fuel loading and transport in a safe manner and in compliance with approved procedures. The inspectors also made direct observations and reviewed selected records to ensure the licensee had identified each fuel assembly placed in the ISFSI, had recorded the parameters and characteristics of each fuel assembly, and had maintained a record of each fuel assembly as a controlled document.

b. Findings

No findings of significance were identified.

.3 Holtec Multi-Purpose Canister Helium Leak Rate Testing (IP 60853)

a. Inspection Scope

On August 25 and 26, 2009, the inspectors witnessed helium leak testing of Holtec Multi-Purpose Canisters (MPC) # 191 and 186 by Leak Testing Specialists, Inc. (LTS) under contract to the canister fabricator, Holtec International. The inspectors observed LTS personnel perform the helium leak rate testing in accordance with Procedure No. MSLT-MPC-HOLTEC, "Helium Mass Spectrometer Leak Test Procedure - Hood Technique." Revision MPC-Field-LT-01. The inspectors also verified the Mass Spectrometer Leak Detector (MSLD) had a minimum sensitivity of 2.0E-9 atm-cc/second, and was properly calibrated using a calibrated leak standard of 7.46 E-8 atm-cc/second. The measured helium leak rate on MPC #191 was determined to be 2.3E-8 atm-cc/second, which was less than the maximum allowable leak rate of 1.0E-7 atm-cc/second.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On October 6, 2009, the senior resident inspector presented the inspection results to Mr. Rusty West and other members of the staff, who acknowledged the findings. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

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

- Unit 2 Technical Specification 3.4.3, Safety/Relief Valves, required that twelve of thirteen MSRVs lift at a setpoint within plus or minus three percent of a specified value. Contrary to this, during TS required surveillance testing following the Unit 2 Cycle 15 refueling outage, the licensee discovered that the lift setpoints of seven MSRVs exceeded the TS allowed pressure band. This TS violation was entered into the licensee's CAP as PER 175990. The finding was determined to be of very low safety significance because the as-found lift setpoint conditions of the Unit 2 MSRVs were analyzed and determined to meet the design basis criteria for the most limiting over-pressurization events.

- Unit 2 Technical Specification 3.8.7, Electrical Distribution System – Operating, required that the AUTO/MANUAL transfer switch on the 2D RMOV Board be in AUTO to maintain the board operable, otherwise declare the associated RHR subsystem inoperable. TS LCO 3.5.1, Emergency Core Cooling System – Operating, required that Unit 2 be placed in Mode 3 in 12 hours and Mode 4 in 36 hours if one low-pressure ECCS subsystem is inoperable for greater than seven days. Contrary to this, the licensee discovered during routine surveillance testing that the automatic transfer switch on the 2D RMOV Board was inadvertently left in the MANUAL position between June 19, 2009, and July 18, 2009, without taking the TS required action specified above. This TS violation was entered in the licensee's CAP as PER 176648. The finding was determined to be of very low safety significance because it did not constitute a total loss of safety function since Division II of LPCI would have been available during an accident.

- 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, required, in part, that measures shall be established to assure that conditions adverse to quality, such as defective equipment, were promptly corrected. Contrary to this, the licensee determined that it had failed to take adequate measures consistent with industry operating experience and vendor recommendations to assure that an identified equipment defect associated with MSRV stem thread degradation was corrected, which subsequently resulted in a failure of a Unit 2 MSRV to properly lift and reseat. This condition was identified as a result of performing a TS required surveillance procedure. This finding was entered into the licensee's corrective action program as PER 174596 and PER 173480 for the associated root cause analysis. This finding was also determined to be of very low safety because it did not result in exceeding the TS limit for unidentified RCS operational leakage of 5 GPM, nor did the finding affect other mitigation systems resulting in a total loss of their safety function.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Berry, Component Engineering Manager
J. Black, Chemistry Manager
S. Bono, Director of Engineering
J. Bryan, Mechanical Maintenance Supervisor
M. Button, Maintenance Manager
P. Chadwell, Operations Manager
J. Colvin, Engineering Programs Manager
R. Conner, Work Control Manager
P. Donahue, Assistant Engineering Director
J. Emens, Site Licensing Supervisor
D. Feldman, Operations Support Superintendent
A. Feltman, Emergency Preparedness Manager
D. Grissette, Director Site Technical Support
F. Godwin, Licensing Manager
J. Keck, Reactor Engineering Manager
R. King, System Engineering Manager
J. Lewis, Operations Support Superintendent (Acting)
D. Malinowski, Operations Training Manager
M. McAndrew, Operations Superintendent
B. McBay, Superintendent Instrument and Controls
J. McCarthy, Director Safety and Licensing
J. Mitchell, Site Security Manager
J. Morris, Director Training
E. Quinn, Performance Improvement Manager
J. Randich, Plant General Manager
R. Rogers, Director Project Management
M. Roy, RHR System Engineer
P. Sawyer, Radiation Protection Manager
J. Underwood, Site Nuclear Assurance Manager
R. West, Site Vice President

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000296/2009004-01	URI	Unit 3 Reactor Core Isolation Cooling Pump Flow Oscillations (Section 1R15)

Closed

05000260/2009-002	LER	Leak in an ASME Code Class 1 Reactor Pressure Boundary Pipe (Section 4OA3.3)

05000260/2009-003	LER	Main Steam Relief Valve As Found Setpoint Exceeded Technical Specification Lift Pressure (Section 4OA3.4)
05000259, 260, and 296/2009-003	LER	A Train Standby Gas Treatment System Inoperable Longer Than Allowed by the Technical Specifications (Section 4OA3.5)
05000260/2009-004	LER	Technical Specification Shutdown Due to Rise in Unidentified Drywell Leakage (Section 4OA3.6)
05000260/2009-005	LER	Reactor Motor Operated Valve Board and Residual Heat Removal Subsystem Inoperable Longer than Allowed by the Plant's Technical Specifications (Section 4OA3.7)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

Procedure 3-OI-75 Core Spray System, Attachment 1 Valve Lineup Checklist, Effective Date 12/04/07
Procedure 3-OI-75 Core Spray System, Attachment 2 Panel Lineup Checklist, Effective Date 04/08/08
Procedure 3-OI-75 Core Spray System, Attachment 3 Electrical Lineup Checklist, Effective Date 12/04/07
Drawing 3-47E812-1, Flow Diagram High Pressure Coolant Injection System, Rev. 59
Procedure 3-OI-73, High Pressure Coolant Injection System, Rev. 42 and Attachments 1, 2 and 3
Drawing 2-47E812-1, Flow Diagram High Pressure Coolant Injection System, Rev. 41
Procedure 2-OI-73, High Pressure Coolant Injection System, Rev. 82
Procedure 2-OI-73 Attachment 1, Valve Lineup Checklist, Rev.82
Procedure 2-OI-73 Attachment 2, Panel Lineup Checklist, Rev. 81
Procedure 2-OI-73 Attachment 3, Electrical Lineup Checklist, Rev. 82
Procedure 2-OI-73 Attachment 4, Instrument Lineup Checklist, Rev. 81
General Design Criteria Document BFN-50-7073, High Pressure Coolant Injection System, Rev. 19
NUREG/CR-6022, High Pressure Coolant Injection (HPCI) System Risk-Based Inspection Guide For Browns Ferry Nuclear Power Station, September 1993
PER 152914, Maintenance Rule A1 status for U2 HPCI
PER 160047, Unplanned entry into LCO
PER 160537, HPCI declared Inoperable

Section 1R05: Fire Protection

Fire Protection Report, Volume 1, Fire Hazards Analysis, Section 2, Fire Area 16, Rev. 5
Fire Protection Report, Volume 1, Fire Hazards Analysis Units1/2/3, Rev. 0
Fire Protection Report, Volume 2, Section IV.11, Pre-plan No CB2-593, Rev. 8
Fire Protection Report, Volume 2, Section IV.12, Pre-plan No CB3-593, Rev. 7
Fire Protection Report, Volume 2, Section IV.14, Pre-Plan No. TB1-586, Rev. 8
Fire Protection Report, Volume 2, Section IV.15, Pre-Plan No. TB1-617, Rev. 8
Fire Protection Report, Volume 2, Section IV.16, Pre-Plan No. TB2-586, Rev. 8
Fire Protection Report, Volume 2, Section IV.17, Pre-Plan No. TB3-586, Rev. 8
Fire Protection Report, Volume 2, Section IV.18, Pre-Plan No. TB3-617, Rev. 8
Drawing 2-47W2392-301 and -313, Fire Protection – 10 CFR 50 Appendix R Penetration Seal Location Drawings EL 593, Rev. 1

Section 1R06: Flood Protection

WO 09-710207, Perform Quarterly Door Inspections (May 2009)
WO 09-715058, Perform Quarterly Door Inspections (July 2009)
MPI-0-260-DRS001, Inspection and Maintenance of Doors
PER 177155, Obstruction Prevented Inspection of Door 2-260-0041

WO 07-714987, Perform Calibration and Functional Check of Unit 2 Rx Building Floor Drain Sump Pump A and B Level Switches (2-LIS-77-008A/B)
WO 07-717688, Perform Calibration and Functional Check of Unit 3 Rx Building Floor Drain Sump Pump A and B Level Switches (3-LIS-77-008A/B)
EPI-0-77-SWZ001, Calibration and Inspection Radwaste Sump Pump and Seal Header Level Switches
WO 07-713406, Perform Functional Check of the Unit 3 Flood Level Switches for the Reactor Building (December 2007)
WO 07-726538, Perform Functional Check of the Unit 1 Flood Level Switches for the Reactor Building and the Equipment Access Water Seal Level Switch (October 2008)
WO 09-710822, Perform Functional Check of the Unit 3 Flood Level Switches for the Reactor Building (August 2009)
EPI-0-77-SWZ002, Functional Check of the Reactor Building Flood Level and Equipment Access Lock Water Seal Level Switches
PER 201532, PM Process Weaknesses for Inspection and Maintenance of Watertight Doors
PER 203557, Watertight Flood Door Deficiencies
PER 203558, Watertight Flood Door with Equipment Interference
PER 203389, Personnel Operation of Watertight Floor Doors

Section 1R11: Licensed Operator Requalification Program

OPL 178.073, Unit 3 Simulator Exercise Guide, Power Reduction, Recirculation Pump Trip, Reactor Power Oscillations, and ATWS with MSIVs Open

Section 1R12: Maintenance Effectiveness

PER 152026, U2 CRD Pump Vibration in High Alarm
PER 152918, Backup CRD Removed from Service with High Vibration on Available Pump
PER 153013, 2A CRD Pump Tagged and Maintenance Not Notified
PER 153157, 2A CRD Pump High Vibrations
PER 154089, 2A CRD Pump Procedure Errors
PER 154399, 2A CRD Pump Loose Foundation Bolts
PER 156441, 2A CRD Pump Motor-to-Speed Increaser Gap
PER 156491, 2A CRD Pump Failure Analysis
PER 162490, 2A CRD Pump Wiped Bearing
PER 164398, CRD Pump Vendor Manual and Procedure for Stainless Steel Casing
PER 171970, CRD Pump 2A Failed PMT on High Bearing Temperature
PER 176224, CRD Pumps in (a)(1) Status
Unit 1, 2 & 3 Function 085-B & D (a)(1) Plan, Rev. 0
CDE 725, 2A CRD Unavailability
MREP Meeting Minutes dated 12/15/2008
MREP Meeting Minutes dated 04/22/2009
MREP Meeting Minutes dated 07/17/2009
MREP Meeting Minutes dated 08/20/2009
MCI-0-085-PMP001, Control Rod Drive Pump Maintenance, Rev. 21
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SPP-6.6, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting - 10C FR 50.65, Rev. 9
0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting – 10 CFR 50.65, Rev. 34
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PER 173480, Root Cause Analysis for 2-PCV-1-23 Fail to Cycle
PER 174596, GE SIL 646 Recommendations Not Implemented
PER 57299, Applicability Review of GE SIL 646
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MCI-0-001-VLV002, Main Steam Relief Valves Target Rock Model 7567 Disassembly, Inspection, Rework and Reassembly, Rev. 35
WO 09-718047-000, BFN-2-PCV-001-0023 Troubleshooting Plan
General Electric Services Information Letter (SIL) No. 646, Target Rock Safety Relief Valve Failure to Fully Open, December 20, 2002
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Technical Specifications and Bases 3.5.1, ECCS – Operating, Amendments 294 and 286 respectively
Technical Reference Manual and Bases 3.4.2, Relief Valves, Rev. 0
2-SR-3.4.3.2, Main Steam Relief Valves Manual Cycle Test, Rev. 4

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

0-TI-367, BFN Equipment to Plant Risk Matrix, Rev. 10
SPP-7.1, On-Line Work Management, Rev. 13
SPP-7.3, Work Activity Work Management Process, Rev.1
BFN Plant Risk and Protected Equipment Report (7/22 and 7/23/09)
BFN Plant Risk and Protected Equipment Report (08/10/09)
BFN Plant Risk and Protected Equipment Report (09/02/2009)
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Unit 2 Sentinel reports (09/02/09)
T-0 Summary Report for Work Week #2930

Section 1R15: Operability Evaluations

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PER 154248, Water in Unit 1 7-Day Tanks
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Design Criteria BFN-50-7082, Standby Diesel Generator, Rev. 14

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FSAR, Section 4.4, Nuclear System Pressure Relief System, BFN-22
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FE 43600 for PER 173480, 2-PCV-1-23 Failed to Cycle (FE 43546 Revision)
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BFN Unit 2 Technical Specifications and Bases 3.5.1, ECCS – Operating, Amendments 294 and 286 respectively
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PER 168144, SSA0903 Audit PER on RCIC Degraded Condition
PER 200183, RCIC Flow Oscillations during Unit 3 Scram
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BFN USFAR Section 4.7, Reactor Core Isolation Cooling System
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3-SI-3.2.4.(DG D), EECW Check Valve Test on Unit 3 D EDG
WO 09-719495-000, Disassemble, Inspect, Clean, and Reassemble 3D EDG Coolers(2)
MCI-0-082-CLR001, Standby Diesel Engine Water Coolers Disassembly, Inspection, Rework, and Reassembly for 3D EDG Coolers 3-HEX-082-000D1 and D2
PER 176376, PMs for 4KV Bus-tie Board (BFN-3-BDAA-210-1) Were Cancelled
Functional Evaluation #43620 for PER 176376
10 CFR 50.59 Screening Review for FE 43620

Section 1R19: Post-Maintenance Testing

2-SR-3.5.3.3, RCIC System Rated Flow at Normal Operating Pressure, Rev. 41
PER 203487, U2 Damaged RGSC Potentiometers
PER 203537, U2 RCIC Turbine Failed to Start During Automatic Initiation
PER 203538, U2 Manual Trip Low Water Level
WO 09-722264-000, Replace U2 RCIC Woodward EGM Control Box
WO 09-722370-000, Realign U2 RCIC Overspeed Trip Linkage Follower
WO 09-719914-000, Walkdown and Inspect Linkage on RCIC Trip Throttle Valve 3-FCV-71-9
WO 09-719914-001, 3-FCV-71-9 Failed to Trip, Operations Verify Valve Closed and Re-perform Test
WO 09-719914-002, Troubleshoot RCIC Stop Valve 3-FCV-71-9 Trip Solenoid (3-XX-071-0009) Coil
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3-SI-4.5.C.1(2), EECW Pump Operation, Rev. 103
WO 09-720669-000, C3 EECW Pump Impeller Gap Adjustment
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PER 202145, U3 RCIC Failed PMT
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MPI-0-071-TRB001, Reactor Core Isolation Cooling (RCIC) Turbine Preventive Maintenance, Rev. 24
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3-SR-3.8.1.1(3D), Diesel Generator 3D Monthly Operability
WO 09-719495-000, Disassemble, Inspect, Clean, and Reassemble 3D EDG Coolers
MCI-0-082-CLR001, Standby Diesel Engine Water Coolers Disassembly, Inspection, Rework, and Reassembly for 3D EDG Coolers 3-HEX-082-000D1 and D2
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3-SR-3.8.1.1(3B), Diesel Generator 3B Monthly Operability Test, Revision 33
MCI-0-082-CLR003, Standby Diesel Engine Aftercooler Disassembly, Inspection, Rework and Reassembly, Rev. 15
ECI-0-000-MOV009, Testing of Motor Operated Valves Using MOVATS Universal Diagnostic System (UDS) and Viper 20, Rev. 22
0-TI-230V, Vibration Program, Rev. 6
BFN Unit 3 Technical Specifications Section 3.8.1, AC Power Sources - Operating
BFN USFAR Section 8.5, Standby AC Power Supply and Distribution

2-SR-3.3.5.1.6(B I), Functional Testing of RHR Loop I Pump and Minimum Flow Valve Logic, Revisions 16, 17 and 18
ECI-0-000-MOV009, Testing of Motor Operated Valves Using MOVATS Universal Diagnostic System (UDS) and Viper 20, Rev. 22
BFN Unit 2 Technical Specifications Section 3.5.1, ECCS - Operating
BFN USFAR Section 4.8, Residual Heat Removal System

3-SI-4.4.A.1, Standby Liquid Control Pump Functional Test, Rev. 39
Drawing 3-47E854-1, Flow Diagram Standby Liquid Control System, Rev. 9
3-SR-3.5.1.6(CSII), Core Spray Flow Rate Loop II
BFN Unit 3 Technical Specifications Section 3.5.1, ECCS - Operating

Section 4OA1: Performance Indicator Verification

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NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Rev. 5
SPP-3.4, Performance Indicator for NRC Reactor Oversight Process for Compiling and Reporting PIs to the NRC, Rev. 8
Unit 1 Mitigating System Performance Index (MSPI) Basis Document, Revision 3
Unit 2 Mitigating System Performance Index (MSPI) Basis Document, Revision 2
Unit 3 Mitigating System Performance Index (MSPI) Basis Document, Revision 2

Records and Data
Unit 1, 2 and 3 Second Quarter PI Summary Sheet
Unit 1, 2 and 3 MSPI Derivation Reports for Unreliability Index for each applicable system (Emergency AC (EAC) Power, HPCI, Heat Removal System (RCIC), RHR and Cooling Water Systems) for the second quarter 2009.
Unit 1, 2 and 3 MSPI Derivation Reports Unavailability Index for each of the above systems for the second quarter 2009
Maintenance Rule Unavailability and Unreliability Data and Spreadsheets for EAC, HPCI, RCIC, RHR, and Cooling Water Systems
LCO Tracking Log from July 1, 2008 to June 30, 2009
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CDE 665, B DG Heat Exchanger Leak
CDE 679, B3 EECW Strainer Failure
CDE 685, Unit 3 RCIC Steam Line Drain Line Condensate Buildup
CDE 681, A DG Lube Oil Pump Failure
CDE 689, Unit 1 HPCI Lube Oil High Moisture
CDE 690, Unit 2 HPCI Lube Oil High Moisture
CDE 694, A3 EECW Pump ARV Failure
CDE 705, B DG Exceeded MR UA in July 2008
CDE 709, 3D RHR and CS Pumps Fail to Start during 3D DG Load Acceptance Test
CDE 722, Faulty DG C Div II Unit Priority Retrip Relay
CDE 729, Unit 1 RCIC Turbine Control Valve (1-FCV-71-10) Failed Close
CDE 730, Unit 1 RCIC Main Steam Admission Valve (2-FCV-71-03) Failed Close
CDE 744, Unit 2 HPCI Steam Admission Valve (2-FCV-73-16) Failure to Close Completely
CDE 754, 1A CS Pump Failed to Trip

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PER 127972, Unplanned LCO for B1 RHRSW Pump
PER 133118, Common Cause Modeling for RHRSW/EECW Pumps
PER 147593, Diesel Data Entry Late for INPO CDE Database
PER 153012, MSPI Basis Document Discrepancies
PER 153144, U1 HPCI MSPI
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BFN-ODM-4.16, Operator Workarounds/Burdens/Challenges, Rev. 0
SPP-7.1, On Line Work Management, Rev. 13
PER 150886, NRC Questions on Priority Assigned to OWAs
PER 151424, NRC Inspection of OWA Program
PER 151425, NRC Identified OWA Issue on PERs not being written on OWAs
PER 151686, OWA Process Does Not Meet Procedural Guidance (SA CRP-PA-09-004)
PER 163316, OWA Key Performance Indicator is Red on Unit 1
PER 163317, Operator Burden Non-Outage KPI Red for Five Months
PER 163318, Operator Challenges Non-Outage KPI Red for Unit 3
PER 167756, Missed OWA Action on Monitoring 3B VFD
PER 167938, Discrepancies Identified with OWA during NA Audit SSA0903
PER 169116, OWA Program Snap Shot Self-Assessment BFN-OPS-S-09-009
PER 169788, NSRB April 2009 Exit Comments on Performance Indicators
PER 169795, NSRB Identified BFN Operations Significant Performance Deficiency
PER 172226, OWA Program Effectiveness Review (BFN-OPS-S-09-009)
Self-Assessment CRP-PA-08-004, PI&R Self Assessment
Self-Assessment CRP-PA-I-09-006, Corrective Action Program
Self-Assessment BFN-OPS-S-09-001, Turn Around Plan Progress
Self-Assessment BFN-OPS-S-09-009, Operator Work Around Program
Self-Assessment BFN-OPS-S-09-015, Operator Work Around Program
NA Audit SSA0903, Corrective Action Program

Section 4OA3: Event Follow-up

LER 05000260/2009-002, Leak In An ASME Code Class 1 Reactor Pressure Boundary Pipe, Rev. 0
Drawing 2-47E811-1, Flow Diagram Residual Heat Removal System, Rev. 65
PER 172551, Pressure Boundary Leak 2-SHV-74-49
BFN Operator Logs dated May 31, 2009
2-SI-3.3.1.A, ASME Section XI System Leakage Test of the Reactor Pressure Vessel and Associated Piping (ASME Section III, Class 1 and 2), Rev. 25
Unit 1 TS 3.6.4.3, Standby Gas Treatment (SGT) System, Amendment 251
Unit 1 TS 5.5.7, Ventilation Filter Testing Program (VFTP), Amendment 235
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Procedure 0-OI-65, Standby Gas Treatment System, Rev. 52
Procedure 0-SR-3.6.4.1, Standby Gas Treatment Train Operation, Rev. 15 and Rev. 16
Procedure 0-SR-3.6.4.3.2(A HTR), Standby Gas Treatment Filter Train A Humidity Control, Rev. 19 and 20
Procedure 1-ARP-9-22B, Rev. 12 and 13
Procedure 2-ARP-9-3B, Rev. 22 and 23

Procedure 3-ARP-9-3B, Rev. 17 and 18
PER 174416, Standby Gas Treatment Relative Humidity Heater Relay Malfunction Not Properly Evaluated as Affecting Technical Specification Operability
PER 174597, 'A' SGT Inoperability, Unplanned LCO Entry
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Unit 2 TS 3.5.1, ECCS – Operating, Amendment 294
Unit 2 TS Bases B3.8.7, Distribution System - Operating, Rev. 0
Browns Ferry FSAR, Section 8.5.3.5, Distribution System
Procedure 0-OI-57B, 480V/240V AC Electrical System, Rev. 184
Procedure 0-GOI-300-1, Attachment 15.13, Monthly Emergency Control Switch Verification – Unit 2, Rev. 202
PER 176648, Mispositioned Manual-Auto Transfer (43) Switch on 480 Vac RMOV Board 2D

Section 4OA5: Other Activities

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MSI-0-079-DCS035, Dry Cask Storage Campaign Guidelines, Rev. 5
MSI-0-079-DCS036, ISFSI Abnormal Conditions Procedure, Rev. 2
MSI-0-000-LFT001, Lifting Instructions for Control of Heavy Loads, Rev. 51
MSI-0-079-DCS100.1, HI-STORM Initial Inspection, Rev. 0
MSI-0-079-DCS100.2, MPC Initial Inspection, Rev. 0
MSI-0-079-DCS100.4, HI-TRAC Annual, Pre-Use and Storage Inspection and Maintenance, Rev. 0
MSI-0-079-DCS100.5, ISFSI Ancillary Equipment Lay-up and Pre-Use Preparations, Rev. 0
MSI-0-079-DCS100.6, HI-STORM and MPC Storage and Pre-Use Inspection, Rev. 0
MSI-0-079-DCS200.1 , Dry Cask Preparations, Start Up and Shut Down, Rev. 1
MSI-0-079-DCS200.2 , MPC-Loading and Transport Operations, Rev. 5
MSI-0-079-DCS300.2, Alternate Cooling Water System Operation, Rev. 0
MSI-0-079-DCS300.3, Dolly Operation, Rev. 0
MSI-0-079-DCS300.4, HI-STORM System Site Transportation, Rev. 1
MSI-0-079-DCS300.5, Cask Transporter Operation, Rev. 1
MSI-0-079-DCS300.6, Canister Drying System Operation, Rev. 0
MSI-0-079-DCS300.9, Helium Backfill System Operation, Rev. 1
MSI-0-079-DCS400.1, ISFSI Abnormal Conditions Procedure Placing the MPC In a Safe Condition, Rev. 0
0-GOI-100-3B, Operations in Spent Fuel Storage Pool Only, Rev. 43
NFTP-100, Fuel Selection for Dry MPC Storage, Rev. 4

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